JUN 12 1979

WORKING PAPER NO. 79-2

POTENTIAL MARKETS FOR THERMAL COAL IN CANADA, 1978-2000

CANADIAN RESOURCECON LIMITED

JUNE, 1979

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I INTRODUCTION

This study is a preliminary assessment of the potential demand for thermal coal in Canada to the year 2000. Two major categories of thermal coal demand are evaluated.

i) demand by industrial consumers such as cement plants, pulp and paper plants, etc.;

ii) demand by thermal-electric generating plants.

Transportation costs to the identified market locations from four representative coal supply areas in Canada are estimated; these costs are then deducted from the forecast coal market prices to yield net-back figures attainable at mine site locations.

The potential demand for thermal coal in the industrial sector is discussed individually by the following major energy using categories:

pulp and paper
cement
lime
chemicals
iron and steel*
oil sands
smelting and refining
potash.

Fossil fuel energy use by the "general" industrial category is also evaluated. The demand forecasts are detailed on a provincial or regional basis.

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* *The demand for metallurgical coal in Canada by the steel industry is not included in this study.*

Coal market price estimates are made within an explicit forecast of competing natural gas and fuel oil prices in Canada's various regions. The analysis is conducted under a single set of forecast oil and gas prices; a sensitivity analysis is then conducted to evaluate the impact on thermal coal demands of either higher or lower prices than those chosen in the base case. Coal market prices for each industry group and each geographic area in Canada are calculated based on the estimated competitive prices of natural gas or heavy fuel oil less a discount factor to reflect the increased capital and operating cost associated with coal use. In considering potential industrial coal markets, assumptions are also made concerning future electric energy prices relative to fossil fuels and the availability and price of wood residues; wood residues are becoming an increasingly important source of energy to the pulp and paper sector as fossil fuel prices increase.

The demand for thermal coal by thermal electric plants is made on a provincial basis. Demand estimates to 1990 are based on discussions with personnel from all major utilities and an assessment of their most current load growth forecasts and plans for future generating facilities. For the period beyond 1990 the assumed choices of generating plant are based on estimated future costs of alternative generating technologies and directional statements of intentions by utility planners and policy makers.

With respect to coal transportation costs the emphasis of this analysis is to calculate costs associated with the rail movement of coal in Canada, together with marine transportation costs (including terminal charges) on the Great Lakes and also via the Panama Canal. A summary of current available information concerning costs associated with pipeline movements of coal slurries and of electric transmission of energy from mine-mouth electric generating plants is presented.

Many interviews were held across Canada in the conduct of this study with representatives from major industry groups, electric utilities, transportation companies and federal and provincial government departments; a list of organizations whose views were sought is attached as Appendix A. Our appreciation is also extended to Norcen Energy Resources Limited who allowed the consultants full use of an earlier study commissioned by them entitled "Thermal Coal Markets in Ontario and British Columbia, 1980-1990."

This report reflects a level of effort equal to approximately 6 man-months. It was prepared over the period November 1978 to February 1979. It is not to be viewed as an exhaustive final analysis but rather as a general treatment whose purpose is to provide a first approximation estimate of future coal demands within a specified framework of energy prices and transportation costs. The discount factors developed in this analysis at which coal would be competitive with natural gas or heavy fuel oils are approximate. In those industrial sectors showing the most promise as potential coal markets, it will be desirable that further work is carried out to more precisely define price levels at which coal would be competitive and to more precisely define transportation costs to specific plant locations.

II SUMMARY AND CONCLUSIONS

The potential demand for thermal quality coals in Canada by the thermal electric and industrial sectors could be in the order of 100 million tons annually by 2000, as follows:

	1990	2000
	(million tons)	
Thermal electric demand	45-53	54-81
Industrial demand	19	24
Total	62-72	78-105*

The demand forecasts and qualifying assumptions under which the industrial sector forecasts are made are elaborated upon below.

1.0 ENERGY PRICE ASSUMPTIONS

Coal price estimates which can be achieved in various industrial markets are made within an explicit forecast of competing natural gas and fuel oil prices in Canada's various regions. Future coal prices at the point of consumption in industrial markets are estimated based on these competitive energy prices less a discount factor to reflect the additional capital and operating costs associated with coal use.

The Canadian crude oil price, which is the basis of establishing industrial fuel oil and natural gas prices, is forecast to increase from the present level of $13.76/bbl. at the Toronto city gate (December 1978) to $20.00/bbl. (1978$) in 1990; it is forecast to remain constant at $20 (1978$) from 1990 to 2000. It is assumed natural gas will continue to be regulated at 85% of the crude oil price at the Toronto city gate.

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* *All tons in this report are short tons of 2000 lbs.*

Based on this forecast natural gas and heavy fuel oil prices to industrial users in Canada will vary from about $2.25/MMBtu in Alberta to $3.00/MMBtu in northern Ontario (customers off main oil and gas supply routes will pay more). Prices to smaller industrial accounts, typical of those in the General industrial category, would be higher, ranging from about $2.40/MMBtu to $3.80/MMBtu depending on province.

Wood residues (hog fuel) such as sawmill waste and bark will become an increasingly important source of energy to the pulp and paper sector as fossil fuel prices increase. The assumption in this study is that in each province with a pulp and paper industry hog fuel will be utilized to the extent that it is forecast to be available. This serves to modify the potential coal demand in the industry.

Electric energy prices to large industrial customers are substantially above delivered fossil fuel prices in all provinces. They are forecast to remain this way over the forecast period so that no significant shift in the fossil fuel vs. electric energy share of the industrial market is expected.

Coal will certainly have to sell at a discount from prevailing heavy fuel oil or natural gas prices to be competitive in industrial applications. The size of the necessary discounts as calculated in this report on an industry by industry basis are shown in Table 1.

TABLE 1: NECESSARY COAL PRICE DISCOUNT BY INDUSTRY GROUP

Sector	Existing Plant ($/MMBtu)	New Plant	Basis of Estimate
Pulp & paper	1.40	1.00	400,000 lb./hr. boiler
Cement	0.30	0.20	1 MM tons/yr. capacity
Lime	0.40	0.25	100,000 tons/yr. capacity
Chemicals	1.55	1.15	200,000 lb./hr. boilers
Steel	0.75	0.50	Blast furnace injection
	0.75	0.50	Direct reduction
Oil Sands	-	0.75	In-situ steam project
Smelting & Refining	1.25	0.75	Larger smelter energy uses only
Potash	1.75	1.25	100,000 lb./hr. boiler
	1.25	-	In-situ project
General	2.15	1.50	50,000 lb./hr. boiler
	-	1.50-2.50	Coal gasification

2.0 COAL TRANSPORTATION COSTS

Transportation costs are developed for each transportation mode or service, and for various distance ranges and annual volume levels. Costs have been calculated on a dollar per million Btu basis for each potential component of the transportation system between any of the four coal source locations and any potential market. Transportation costs so calculated are deducted from the prices at which coal is forecast to be able to penetrate various industrial markets to yield coal mine net-backs at the four representative mine locations which are considered (Coalspur and Drumheller in Alberta; Bienfait, Saskatchewan; Cape Breton, Nova Scotia).

Estimated railway tariffs are shown in Table 2 and are seen to vary considerably depending on volume and distance. The transportation cost of a 1400 mile rail haul such as from Coalspur to Thunder Bay would range from $20.30/ton for unit train movements to $28.70/ton for car lots.

TABLE 2: RAILWAY COAL TRANSPORTATION COSTS

Distance (miles)	Transportation Cost Unit Train	 Hopper Car	 Car Lot	 Car Block
	(¢/ton-mile)			
50	-	-	16.50	13.20
100	2.00	2.40	9.35	7.50
200	1.71	2.05	5.45	4.35
300	1.59	1.91	4.05	3.23
400	1.51	1.81	3.25	2.60
500	1.49	1.79	2.84	2.27
600	1.48	1.78	2.63	2.16
700	1.45	1.74	2.48	2.09
800	1.45	1.74	2.39	2.06
900	1.45	1.74	2.31	2.04
1000	1.45	1.74	2.23	2.03
1200	1.45	1.74	2.11	2.00
1400	1.45	1.74	2.05	2.00
1600	1.45	1.74	2.05	2.00
1800	1.45	1.74	2.05	2.00
2000	1.45	1.74	2.05	2.00

SOURCE: Canadian Resourcecon Limited

Intermodal transfer terminals on the West Coast, at Thunder Bay and in the Montreal area will play a role in the movement of coal to some industrial markets. Terminal charges over the forecast period are estimated as follows:

Terminal Charge	Cost $/ton (1978$)
West Coast	2.20
Thunder Bay	2.60-3.00
Montreal Area	2.50

The transportation of coal by ship is evaluated over the various routings below:

- Thunder Bay to various Great Lakes ports;
- Montreal area to various Great Lakes ports;
- Cape Breton to various St. Lawrence and Great Lakes ports;
- Vancouver area to Montreal area via the Panama Canal.

For the first three routings Great Lakes bulk carriers would be used. It is assumed that maximum vessel size would be 730 feet, allowing passage through locks of the Welland Canal and coal cargoes of a maximum of somewhat more than 30,000 tons. For the Panama routing ships would be Panamax type bulk carriers with draft limited to the 35 to 40 feet available at Montreal area terminals. Typical coal loads would be approximately 45,000 tons. Estimated coal transportation costs for ship transport are shown on Table 3.

In some cases trucking will be the most attractive means of moving coal all or part of the way to an industrial consumption point. For situations in which the industrial consumer lacks rail access, the choice of truck is a simple one. Where rail and truck are in competition, the specific circumstances will dictate the choice. In general, distances up to about 50 miles appear to be most effectively served by truck, but favourable

TABLE 3: ESTIMATED SHIP TRANSPORTATION COSTS FOR VARIOUS COAL TYPES ON VARIOUS ROUTINGS

($/MMBtu's)

	FROM:	Cape Breton	Thunder Bay	Thunder Bay	Thunder Bay	Vancouver		
	TYPE:	Cape Breton	Coalspur	Drumheller	Bienfait	Coalspur(1)	Coalspur(2)	Coalspur(3)
TO:	Lake Huron (north)	0.488	0.123	0.142	0.188	0.802	1.188	1.325
	Lake Huron (south)	0.464	0.150	0.174	0.229	0.775	1.161	1.298
	Lake Erie	0.428	0.191	0.221	0.292	0.734	1.120	1.257
	Lake Ontario	0.392	0.243	0.282	0.372	0.693	1.079	1.216
	Montreal	0.240	0.416	0.482	0.635	0.500	0.886	1.023

SOURCE: Canadian Resourcecon Limited

(1) Foreign vessel, estimated low contract rate.

(2) Foreign vessel, estimated high contract rate.

(3) Canadian vessel at $22.50 per ton.

railway alignment, siding locations and volume, and a steady flow could reduce this distance. Alternatively, an indirect rail routing and irregular flows could extend the trucking distance to over 150 miles -- the distance a driver could cover on a round-trip basis on a single shift.

Slurry pipelines and electric transmission are given brief consideration in this study as possible alternative systems for coal transportation. The transportation cost figures for these modes are uncertain however and the cost estimates which are discussed are not used in the subsequent determination of coal mine net-backs.

For purposes of calculating coal mine net-backs transportation costs are assumed to remain constant over the forecast period, in 1978 dollars. Because transportation costs are such an important part of delivered coal costs, this assumption is a significant one. Coal demands will be very sensitive to changes in transportation costs.

3.0 THERMAL ELECTRIC COAL DEMANDS

Total demand for Canadian coal for thermal-electric power generation is forecast to range from approximately 50 to 80 million tons annually by 2000 (Table 4). Total thermal-electric coal demand in Canada including the probable continuing demand by Ontario for U.S. coal, is forecast to be in the range of approximately 70 to 90 million tons. The provinces where most of the coal will be consumed are Alberta, Saskatchewan, and Ontario.

The forecast coal demand in Table 4 is shown in tons as well as Btu's; it should be pointed out the tonnage figures could vary considerably if a different grade of coal were used than the one considered.

All coal requirements shown in Table 4, except those of Ontario, are forecast to be derived from Canadian sources. The total coal requirement by the year 2000, is seen to range from 1343-1560 trillion Btu's, with the upper figure about 16 percent greater than the lower. A much greater variability (42 percent) is evident in the forecast range of Canadian coal requirements, largely as a result of the uncertainty of future Ontario supply sources.

In most of the provincial forecasts of electricity demands the future assumed prices of competing energy forms such as heavy fuel oils, natural gas, or coal are not explicitly stated. The arbitrary assumption in this report is that the coal volumes estimated to be consumed by power plants, as shown in Table 4, are consistent with the base case energy price forecasts made in Chapter III of this report.

No price sensitivity analysis was done regarding the demand for thermal electric coal supplies relative to the prices of fuel oils and natural gas. To the extent that the coal volumes in Table 4 are consistent with the base case energy prices in Chapter III it is obvious that if crude oil and natural gas prices increased more rapidly than this (say to $25/bbl. (1978$) in 1990 and thereafter rather than $20/bbl.), coal volumes consumed by thermal electric plants would increase; two reasons are:

a) coal would become relatively cheaper as a power plant fuel compared to heavy fuel oil or natural gas.

TABLE 4: SUMMARY OF PROJECTED THERMAL ELECTRIC COAL REQUIREMENTS, 1977-2000

Province	1977[1]	1980	1985	1990	1995	2000
				(Million Tons)		
British Columbia	-	-	-	2.9-11.9	2.9-11.9	2.9-11.9
Alberta	8.4[2]	11.5	17.5	23.0	28.3	36.8
Saskatchewan	4.7	7.0	8.1-8.6	9.9-11.0	11.8-13.9	7.5-17.5
Manitoba	1.2	0.3	0.3	0.3	0.3- 1.8	0.3- 1.8
Ontario - Total	9.7[3]	13.7	14.5	14.5	15.0	20.7
- Canadian Coal	(.23)	(2.7)	(3.5)	(3.5)	(3.5- 4.0)	(3.5- 9.7)
Quebec	-	-	-	-	-	-
New Brunswick	0.2[4]	0.5	0.8	1.0	1.0	1.0
Nova Scotia	0.7[5]	1.6	2.4	2.4	2.4	2.4
Newfoundland	-	-	-	-	-	-
Total, All Sources	24.9	34.6	43.6	54.0-64.1	61.7-74.3	71.6-92.1
Total Canadian Coal	15.4	23.6	32.6	43.0-53.1	40.2-63.3	54.4-81.1
				(Trillion Btu)		
British Columbia	-	-	-	45-130	45-130	45-130
Alberta	134	184	280	368	453	589
Saskatchewan	62	77	84-95	109-121	129-153	83-193
Manitoba	18	4	4	4	4-26	4-26
Ontario - Total	253	356	377	377	390	538
- Canadian Coal	(6)	(70)	(91)	(91)	(91-104)	(91-250)
Quebec	-	-	-	-	-	-
New Brunswick	5	12	18	24	24	24
Nova Scotia	17	40	60	60	60	60
Newfoundland	-	-	-	-	-	-
Total, All Sources	489	673	828-834	987-1084	1105-1236	1343-1560
Total Canadian Coal	242	387	542-548	701-798	806-950	896-1272

(1) 1977 figures are from Statistics Canada, Catalogue 57-003, except as noted below.

(2) Energy Resources Conservation Board.

(3) Tonnage is expressed in terms of Tons of 26 million Btu's (Matthew, op.cit.) rather than the actual tonnage used.

(4) New Brunswick Electric Power Commission.

(5) Nova Scotia Energy Council, Nova Scotia Energy Perspectives 1978.

b) electricity demands would increase as fuel oil and natural gas prices in end use markets increased relative to electricity prices.

Coal volumes in such a case would tend toward the high end of the range of demands shown in Table 4. Conversely if oil and natural gas price increases were significantly lower than forecast in Chapter III (say $15/bbl. (1978$) by 1990 and thereafter rather than $20/bbl.) thermal electric coal demands would tend towards the low end of the range.

4.0 INDUSTRIAL COAL DEMANDS

Industrial coal demand in Canada which could be economically supplied from Canadian coal sources is estimated at approximately 19 million tons in 1990 and 24 million tons in 2000 (see Tables 5a and 5b) Three very important assumptions lie behind these forecasts.*

a) the prices of competing energy forms supplied to the industrial sector are as outlined in Chapter III;

b) coal transportation costs, as developed in Chapter VI and which are based on current (1978) information, will remain constant in 1978$ over the forecast period, and;

c) the minimum fob mine-site prices at which coal mining operations at the four typical Canadian sources considered could supply volumes as required and achieve a profitable level of operations are:

	$/ton	$/MMBtu
Bienfait	6.00	0.42
Drumheller (surface mined)	8.00	0.50
Coalspur	20.00	0.91
Cape Breton	35.00	1.40

Over 40% of the forecast total industrial coal demand is in Alberta in both 1990 and 2000; the major industrial consumers in Alberta will be the oil sands, chemicals, and cement industries. Ontario and Quebec are the other major regional markets accounting for approximately 20% each of total forecast

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* *Tonnage figures are calculated using a coal calorific factor of 20 x 10^6 Btu/ton; tonnage figures could vary considerably depending on calorific values of coal actually used.*

TABLE 5a: AGGREGATE INDUSTRIAL COAL DEMAND BY REGION, 1990 and 2000

	Coal Demand	
	10^{12} Btu	10^{6} short* tons
	1990	
British Columbia	19.3	0.97
Alberta	158.7	7.94
Saskatchewan	24.3	1.22
Manitoba	15.8	0.79
Ontario	76.8	3.84
Quebec	74.9	3.75
Atlantic	8.7	0.44
CANADA	378.5	18.93
	2000	
British Columbia	24.2	1.21
Alberta	218.9	10.95
Saskatchewan	32.8	1.64
Manitoba	19.8	0.99
Ontario	86.3	4.32
Quebec	84.5	4.23
Atlantic	11.4	0.57
CANADA	477.9	23.90

* *Coal demand converted into short tons from Btu using a factor of 20 x 10^{6} Btu/ton. Actual calorific values of alternative coal sources considered range from 13 MMBtu/ton for Western Canadian Plains coal to 22 MMBtu/ton at Coalspur and 25 MMBtu/ton at Cape Breton.*

TABLE 5b: AGGREGATE INDUSTRIAL COAL DEMAND BY SECTOR, 1990 and 2000

	Coal Demand	
	10^{12} Btu	10^{6} short tons
	1990	
Pulp and paper	55.6	2.78
Cement	52.4	2.62
Lime	12.7	0.64
Chemicals	102.1	5.11
Iron and steel	27.9	1.40
Oil sands	67.0	3.35
Smelting and refining	35.9	1.80
Potash	13.3	0.67
General industrial	11.6	0.58
TOTAL	378.5	18.93
	2000	
Pulp and paper	59.5	2.98
Cement	55.5	2.78
Lime	13.0	0.65
Chemicals	116.0	5.80
Iron and steel	42.3	2.12
Oil sands	100.5	5.03
Smelting and refining	37.2	1.86
Potash	16.9	0.85
General industrial	37.0	1.85
TOTAL	477.9	23.90

industrial demand; Ontario's principal coal using industries will be the cement, pulp and paper, and steel industries; Quebec's coal demand will be concentrated in the cement, pulp and paper, smelting and refining, and chemical sectors.

On a total Canada basis the industrial sectors offering the largest markets for coal include chemicals, oil sands, pulp and paper and cement. The outlook for coal demand in the various industries studied may be capsulized as follows:

Chemicals: Chemical and petrochemical manufacturers are large users of fossil fuel for fuel and feedstock purposes. Large potential markets exist for coal as a fuel but high coal utilization costs ($1.15 to $1.55/MMBtu) compared to petroleum fuels will result in low net-backs to the coal producer in many applications. The potential feedstock demand for coal in petrochemical manufacture is as large as the fuel demand of this component of the chemical industry; while most, if not all, feedstocks could be derived from coal the cost of doing so would be high; within the framework of the base case price forecast postulated in this report the use of coal as a feedstock in petrochemical production is unlikely.

Cement & Lime: Though potentially not the largest industrial markets for coal in Canada, the relatively low utilization cost of coal ($0.20 to $0.40/MMBtu) in cement and lime manufacturing make these industries the most certain of any to convert to coal use; it is expected that coal will provide 90% of the fuel requirements of these industries over the 1990 to 2000 period.

Pulp & Paper: The pulp and paper industry is a large potential coal user for steam raising purposes but expected large increases in hog fuel use by this industry will modify the scope for coal applications. Though coal utilization costs are high ($1.00 to $1.40/MMBtu) in the order of 3 million tons annually of coal (20 x 10^6 Btu/ton equivalent) could be consumed, over the 1990 to 2000 period, under the competing energy price and other assumptions made in this report.

Iron and Steel: Thermal quality coal has a potential use in the iron and steel industry as a fuel and reductant in direct reduction processes and as a supplementary fuel in the blast furnace steel making process. Over 2 million tons of coal demand are forecast by 2000, two-thirds in Ontario, and one-third in a direct reduction facility (or facilities) in western Canada.

Oil Sands: There is a large potential demand for coal for steam raising purposes in in-situ oil sands operations in Alberta. Assuming three coal based in-situ plants in operation by 2000 would lead to a coal demand of 5 million tons annually (20 x 10^6 Btu/ton basis)*. Much of this coal would likely be captive to oil sands operators such as Esso Resources and Shell who also have large coal holdings in Alberta.

Smelting and Refining: The smelting and refining sector, whose principal products are nickel, copper, zinc, lead and aluminum, have been large users of coal in the past and could become so again. A good potential exists for nearly 2 million tons of coal demand per year over the 1990 to 2000 period. Alcan could consume 0.8 to 1.0 million tons of this amount in the conversion of bauxite to alumina if Cape Breton coal could be supplied at a mine price of $1.40/MMBtu ($35/ton); this market could not be reached economically from western Canadian coal deposits.

* *Nearly 8 million tons annually of 13 MMBtu/ton coal typical of nearby northern Alberta surface mineable coal deposits.*

Potash: Energy in potash manufacture is used both for steam raising (2/3) and drying (1/3); coal is assumed not to be an acceptable fuel type for kiln drying of potash though alternative drying systems utilizing steam could be employed. Individual plants are relatively small steam users* and hence coal utilization costs will be high compared to gas or oil; conversions of existing mining type plants to coal is unlikely though newly designed operations would be possible coal markets. Kalium Chemicals which operates the only solution type plant in Saskatchewan affords the best current coal market opportunity in this industry; Kalium's process is much more energy intensive than mining operations and could consume in the order of 300,000 tons/year of coal (20 x 10^6 Btu/ton basis) if all natural gas uses were converted to coal.

General Industrial: Though the potential fossil fuel use in all other industrial sectors not specified above is very large (nearly 50 million tons of coal equivalent in 2000) only a very small amount of this is considered as a potential coal market. Three quarters of total fossil fuel demand is arbitrarily excluded from consideration by virtue of small plant size, inappropriate fuel use technology, or urban location where coal use would not be suitable. Of the remaining fossil fuel users in this category, who account for 25% of fossil fuel use, coal conversion costs relative to gas and oil are assumed to be high ($1.50 to $2.50/MMBtu); total coal demand is thus forecast to be limited to 0.5 million tons in 1990 and less than 2.0 million tons in 2000.

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* *A 100,000 lb/hour boiler would be adequate for a typical plant size of 1,000,000 tons KCl/year.*

This report identifies volumes of coal which could be economically supplied to Canadian industrial consumers from Canadian coal sources; this is not to say however that Canadian coal suppliers would in fact capture such markets. Foreign coal supply sources, particularly American, could compete strongly for such markets, especially those in eastern Canada. No analysis was undertaken in this study concerning the economic attractiveness of supplying Canadian industrial markets with U.S. or other foreign coal.

4.1 Sensitivity of Industrial Coal Demand to Fuel Oil and Natural Gas Prices

The industrial demand for thermal coals is sensitive to the forecast prices of fuel oil and natural gas. If the Canadian crude oil price (Toronto city-gate) is assumed to reach only $15/ton (1978$) over the 1990 to 2000 period, coal demands will be reduced from the range of 20 million tons per annum to 5 million tons. Conversely if the oil price from 1990 to 2000 is assumed to be in the order of $25/bbl. potential coal demands would double to an approximate 40 million tons per year. Table 6 details potential industrial coal markets under the three oil (and natural gas) price assumptions for 1990 and 2000.

TABLE 6: AGGREGATE INDUSTRIAL COAL DEMAND SENSITIVITY TO PRICE OF ALTERNATIVE ENERGY TYPES

	Crude oil price/bbl.		
	$15.00	$20.00	$25.00
	(10^{12} Btu's)		
1990			
British Columbia	6.1	19.3	30.4
Alberta	11.1	158.7	178.9
Saskatchewan	10.2	24.3	37.9
Manitoba	12.6	15.8	23.3
Ontario	18.0	76.8	246.5
Quebec	32.7	74.9	166.5
Atlantic	7.6	8.7	49.9
CANADA	98.3 (4.92)*	378.5 (18.93)*	733.4 (36.67)*
2000			
British Columbia	6.0	24.2	37.6
Alberta	12.7	218.9	239.2
Saskatchewan	14.5	32.8	47.8
Manitoba	13.7	19.8	27.3
Ontario	18.4	86.3	293.4
Quebec	32.8	84.5	190.1
Atlantic	7.9	11.4	49.7
CANADA	106.0 (5.30)*	477.9 (23.90)*	885.1 (44.26)*

* *Short tons based on average coal calorific value of 20 x 10^6 Btu/ton.*

5.0 OBSERVATIONS RELATED TO THE COAL MINE NET-BACK ANALYSIS

Calculations are made in this study of the levels of net-back which would be available to the "typical" coal mines from various industrial customers at various locations. A number of observations flowing from this net-back analysis, arranged on a regional basis, are presented below.

British Columbia

i) if Coalspur (Alberta foothills) coal cannot capture a British Columbia market, it is unlikely that B.C.'s major reserves or Alberta Crowsnest reserves would capture that market. Reserves in northeast British Columbia are farther from main market centres, and transportation costs would be higher. While mining costs have not been studied there is no apparent reason to believe "Northeast" costs would be lower than in the Alberta foothills. Crowsnest and Coalspur reserves are of a similar distance from main market centres, but it is assumed that Crowsnest mining would be more costly than foothills (Coalspur) mining;

ii) there is a reasonable possibility that relatively low ranking Drumheller (Alberta plains) coal could capture B.C. markets which would not provide a sufficient net-back for the higher ranking Coalspur coal type. The situation would be one in which the difference between Coalspur and Drumheller mining costs (foothills versus plains) would offset higher transportation costs resulting from greater distance and greater cost per unit energy per unit distance.

iii) it is unlikely that low ranking Saskatchewan (Bienfait) lignite could capture any B.C. markets which would not be captured by Coalspur or Drumheller. Mining costs are assumed to be not significantly lower at Bienfait than surface mined coal from the Alberta plains, and the difference would not offset the higher transportation cost resulting from additional distance;

iv) in British Columbia, as in a number of other regions, there are relatively small* coal deposits which have not been considered. Examples include Quinsam River on Vancouver Island, and Hat Creek near Lillooet. These reserves may have significant potential for local use, but cannot be studied in detail on an individual basis in a broad national study of this sort. Further, they are considered unlikely to have a very significant impact on total industrial coal sales through penetration of large markets which would not be captured by the four typical coal types which are under consideration.

Alberta

i) It is not appropriate to use the typical coal type locations for the Alberta market, though the transportation costs developed in Chapter VI may be applied directly or adjusted on the basis of coal's thermal value (e.g. Bienfait transportation costs x 111 percent adjusts a 14.4 MMBtu's per ton rate to a 13 MMBtu's per ton rate for oil sands consumption). Rather than using the typical coal locations it is necessary to estimate the distance to a coal reserve which might be mined for each component of potential demand. With respect to the two typical Alberta coal types, Coalspur and Drumheller, it is worth noting that these locations are representative of bands of similar ranking coal running southeast to northwest through the southern half of the province. For easterly or westerly movements outside the province (excepting market components in western Saskatchewan), Coalspur would be representative of the transportation distance from most of Alberta's higher ranking foothills and mountain reserves; Drumheller, of most of the lower ranking plains reserves. By contrast, within Alberta, other reserves are significantly closer to potential demand locations than Coalspur or Drumheller.

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* *"Small" is used in the context of long-term ability to provide for a significant component of total Canadian industrial energy demand.*

Saskatchewan, Manitoba, Western and Northern Ontario

i) Reasonable net-backs are obtainable from industrial sales in these areas at two or all three of the Western coal sources. The most probable supply source cannot be determined from this study as it depends upon minimization of combined mine-site and transportation costs;

ii) assuming Drumheller surface mining costs will be no lower than Bienfait mining costs, Drumheller coal will not capture any market component east of Saskatchewan. Transportation costs from Drumheller to Manitoba would more than offset its lower transportation cost (per unit energy per unit distance) for movement within and beyond Manitoba.

Eastern Ontario and Quebec

i) Coalspur coal could be moved eastward as far as Quebec City via rail and the Great Lakes, or westward and via the Panama, with little difference in transportation costs

ii) depending on the levels of assumed reasonable net-backs to Coalspur and Bienfait there is (limited) potential for Bienfait coal to capture markets as far east as Montreal (e.g. cement and lime sectors in Table 4);

iii) U.S. coal could capture market components in Ontario and Quebec. Market components which give less than whatever might be estimated as minimum reasonable net-backs to Coalspur or Cape Breton might provide reasonable net-backs to U.S. sources. Thus an assessment of coal's total market could be low, if only Canadian sources are considered.

6.0 ADDITIONAL OBSERVATIONS

i) It should be emphasized that the discount factors, applied to the competitive natural gas or HFO prices, which have been used in this analysis to estimate the market prices for coal are very approximate. In those industrial sectors showing the most promise as potential coal markets more work must be done to better define the most appropriate discount factors to be employed. These discount factors can be expected to vary considerably from plant to plant; also by coal source and type.

ii) Transportation costs to many Quebec and Atlantic locations from western coal sources will be only marginally higher than to southern Ontario.

iii) Transportation costs from western Canada to Ontario, Quebec and the Atlantic region are very high. Sales of western thermal coals could be made to many export markets with lower transport costs than those to eastern Canada. Areas bearing lower transportation costs include Asia's Pacific Rim countries, and coastal portions of the U.S., Mexico, and parts of South America. Depending on market price, net-backs to western producers from serving these markets might in some cases be more attractive than from eastern Canadian markets;

iv) More study should be given by the Canadian coal industry to coal-water slurry pipelines as a possible means of increasing competition in the transport of coal. There have been several active proposals for the construction of such pipelines in the U.S. over the past 2 years for high volume (10 to 25 million tons/annum) long distance systems.

v) Displacement of fuel oils by Canadian coals in Canadian thermal-electric or industrial markets will lead to a higher level of energy self-sufficiency in Canada with attendant employment and balance of payment benefits. Government incentives to encourage coal consumption in new or replacement situations should be provided if necessary to the extent of the public benefit that would be realized. A benefit-cost analysis from a Canadian point of view of expanding the use of Canadian coal should be undertaken.

vi) An important obstacle to the use of coal in the minds of potential users is the uncertainty concerning future coal prices relative to oil, natural gas and other competing energy forms. Confidence must be instilled in potential users that price margins between coal and alternative energy sources can be maintained over the long term. Equipment designs with multi-fuel burning capability would be attractive from this point of view and would encourage the use of coal.

vii) In addition to the use of coal as a fuel, ammonia or methanol plants would consume large quantities of coal for feedstock purposes. These plants would almost certainly be built near mine-site locations. The coal industry should keep abreast of pilot studies that are underway (TVA, U.S. Dept. of Energy) which will test the economic feasibility utilizing coal as a feedstock. Because of the large potential tonnages involved*, additional work is warranted to refine the coal discount factors (compared to natural gas) that would apply to the manufacture of these products.

viii) This report has not investigated the potential for coal use in the large scale mine-site production of high Btu pipeline quality gas. Obviously very large tonnages of coal could be consumed in this way.

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* *A 1500 ton per day ammonia plant would have a feestock coal requirement (8000 Btu/lb.) of over 1.0 million tons annually. A 2000 ton/day methanol plant would require about 1.5 million tons annually.*

III ENERGY PRICE ASSUMPTIONS

The energy price assumptions which lie behind the forecast of industrial thermal coal demands in Canada are presented below. As prices of competing energy forms will play an important part in determining coal demands, energy price assumptions are specified for fuels with which coal must compete including heavy fuel oil, natural gas, wood residues, and electricity. Coal competitive energy prices are forecast for various regions of Canada. Future coal prices at the point of consumption in the various industrial sectors which are examined will be estimated based on the prevailing competitive energy prices less a discount factor to reflect the additional capital and operating costs associated with coal use.

1.0 CRUDE OIL AND NATURAL GAS

1.1 Crude Oil

The price of Canadian oil at the Toronto or Montreal city gates is forecast to increase from its present level (December, 1978) of $13.76/bbl.* to $20.00/bbl. (1978$) by 1990 and remain constant at that price thereafter in constant dollar terms. The price of crude oil delivered to the Maritime provinces or to coastal areas of British Columbia will be the same as the Toronto price, a continuation of the situation which prevails today.**

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* *Comprised of an Alberta field price of $12.75/bbl. plus $0.28/bbl. gathering charge to Edmonton plus $0.73/bbl. transportation tariff via the Interprovincial Pipe Line from Edmonton to Toronto or Montreal.*

** *In eastern Canada the oil price-compensation program operated by the federal government offers refiners buying offshore crude subsidies which serve to reduce the price paid by them for offshore crude to a level approximately equal to the Toronto price. In British Columbia the price of Alberta crude is currently $13.59 comprised of an Edmonton crude price of $13.03/bbl. plus a TransMountain Pipeline tariff of $0.56/bbl.*

The current average price of imported oil to eastern Canada (prior to federal subsidy) is about $17.00/bbl. (Table 7); it is assumed the Canadian oil price will continue to be increased in increments of $1.00/bbl. every 6 months, in current dollars, from July 1, 1979 onwards until the Toronto city gate price reaches parity with the imported price*; this is projected to occur at a price of $17.10 Canadian (1978$)/bbl. in 1984 (Table 7, on the assumption that the imported price will remain constant in 1978$ terms until 1984. After 1984 the Canadian oil price is forecast to increase from $17.10/bbl. in equal annual increments to $20.00/bbl. (1978$) in 1990; this increase of $2.90/bbl. from 1984 to 1990 is equivalent to an average annual increase in the real price of approximately 2.6% per year. From 1990 to 2000 the price is forecast to remain constant at the $20.00/bbl. (1978$) level.

This price forecast assumes that the Canadian oil price will continue to escalate beyond 1984, in real terms, regardless of the performance of international prices after that time. Canada's oil price will continue to be increased to the $20.00/bbl. level (1978$) in order to encourage a high degree of self-sufficiency. Canada, after 15 years of having the productive capacity to be self-sufficient in oil supply, became a net importer of oil in 1976. Our dependency on imported oil will continue to grow rapidly so that by 1985, 30 percent or more of supply will come from foreign sources.** Canada's western reserves of low cost oil, which have been the basis of our productive capacity, continue to decline and alternative domestic supplies from frontier areas, further oil sands development, or coal liquefaction will take many years to develop in quantity and will be costly. The best short term prospect for additional domestic supplies will come from enhanced recovery projects in existing supply areas and acceleration of the development of the "heavy" oil fields in Saskatchewan and eastern Alberta which will be more attractive at higher price levels.

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* *Future price increases will be conditional on oil prices in the U.S. midwest, as well as on international prices; hence there is an implicit assumption that U.S. prices will move up on a comparable basis to international prices.*

** *The NEB in a "base case" forecast estimated the Canadian demand for crude oil and equivalent in 1985 at 2,049,000 b/d and the supply from indigenous sources at 1,394,000 b/d or 68% of the total. NEB, Canadian Oil, Supply and Requirements, September 1978. pp. 165 and 292.*

The cost of encouraging additional domestic supply will be high: a price in the order of $20 per barrel is the break even price for new oil sands plants and production from coal liquefaction will probably be more costly than this*; success in finding oil in Canada's frontier areas has been poor to date suggesting the probability of small field sizes with corresponding high unit production and transportation costs.

Because of such high probable production costs from new sources of supply it seems reasonable to speculate that Canada will support an oil price of $20 per barrel (1978$) by 1990 in furtherance of its self-reliance policy. Indeed, for production from high cost sources of supply, it is probable that Canada will

* *Energy, Mines and Resources Canada, Oil Sands and Heavy Oils; the Prospects, report EP 77-2. pp. 31 and 32. EMR calculate a synthetic oil sands cost of $14 to $16/bbl. (1977$?) exclusive of royalties or economic taxes; this calculation assumes capital charges at 12% per annum.*

support a price in the order of $20 per barrel much sooner than 1990, perhaps by the early 1980's. Our assumption is that a two price system will be administered between now and 1990 which will moderate the increase in the average price of Canadian oil so that the $20 per barrel price will not become fully effective until then. Once such a price has been reached, which is assumed adequate to bring on supplies from high cost sources, it will stabilize at that level as large reserves will then be recoverable.

The forecast of crude oil prices to 2000, used in this analysis, which were based on the above principles, are detailed in Table 7. These crude oil prices are assumed to prevail in all refinery locations from Toronto eastward and in coastal areas of British Columbia.

1.2 Natural Gas

The December 1978 price of natural gas at the Toronto and Montreal city gates was $2.00/MMBtu* or 84.3% of the Toronto city gate crude oil price. For purposes of this analysis it will be assumed that federal and Alberta government policies will continue to regulate the Toronto city gate reference price over the forecast period at 85% of the prevailing crude oil price. For purposes of establishing natural gas city gate prices in other parts of Canada it will be assumed that the pipeline tariff of TransCanada Pipe Lines (TCPL) from the Alberta border to the various rate zones across the TCPL system will remain at December 1978 levels, in 1978$ terms, except for an increase of 1¢/MMBtu per 14.65¢/MMBtu increase (1978$) in the Toronto city gate price of gas to reflect increased pipeline fuel costs as the gas price increases**;

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* *Delivered at 100% load factor.*

** *Assumes fuel use from the Alberta border to Toronto of approximately 7% of throughput.*

implicit in this tariff assumption is that all other TCPL cost of service factors will remain constant in 1978$. Table 7 details the forecast Toronto city gate natural gas prices over the 1978 to 2000 period; Table 8 shows the corresponding forecast "city gate" prices for the various rate zones across TCPL's system.

2.0 INDUSTRIAL HFO AND NATURAL GAS PRICES

In the industrial sector coal must compete primarily with heavy fuel oil or natural gas among the fossil fuel energy forms.

Heavy fuel oil will be considered to be the fossil fuel price setter that coal must compete with in eastern Canada, (from southern Ontario through Quebec to the Maritimes) and in coastal British Columbia. From central British Columbia across the Prairies and into western and northern Ontario, industrial natural gas will be used as the fossil fuel price standard against which coal must compete. Forecasts of heavy fuel oil and natural gas prices to large industrial energy consumers, which correspond to the city gate oil and natural gas price forecasts shown in Tables 7 and 8, are detailed in Table 9.
The HFO price forecast assumes that a constant refinery delivered crude oil price prevails in all areas of eastern Canada and coastal British Columbia, and that HFO will be delivered to large customers in areas easily accessible to refineries at a price equal to 90% of the prevailing crude price, in volumetric terms (approximately 83% of the crude price on a Btu content basis).* Customers in remote areas would face higher prices depending on transportation costs. The large industrial natural gas price is forecast to remain 15¢/MMBtu (1978$) above the

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* *The delivered price of heavy fuel oil in 1978 to industrial users in southern and eastern Ontario and in the Montreal-Quebec City area of Quebec were in the order of 90% of the prevailing Canadian crude price on a volumetric basis. In late 1978 a typical coastal B.C. price of heavy fuel oil to large industrial users was $12.00 to $12.50/bbl. including tax or 88% to 92% of the Vancouver crude oil price of $13.60/bbl.*

TABLE 7: CANADIAN OIL AND NATURAL GAS PRICE FORECAST, TORONTO CITY GATE, 1978-2000

	World Oil[1] Price (current $)	Toronto City Gate[3] Oil Price (current $)	(1978 $)[5]	Toronto City Gate Natural Gas Price (1978 $)
Dec. '78	17.06[2]	13.76[4]	13.76	2.00[6]
1979	18.08	14.26	13.45	1.97
1980	19.17	16.26	14.47	2.12
1981	20.32	18.26	15.33	2.25
1982	21.54	20.26	16.05	2.35
1983	22.83	22.26	16.63	2.44
1984	24.20	24.26	17.10	2.50
1985			17.58	2.58
1986			18.06	2.65
1987			18.54	2.72
1988			19.02	2.79
1989			19.51	2.86
1990			20.00	2.93
1995			20.00	2.93
2000			20.00	2.93

[1] *Average price of foreign crude oil delivered to Montreal. World price is increased at average 6% p.a., equivalent to assumed inflation rate.*

[2] *December 1978 price of crude oil delivered to Montreal via pipeline from Portland, Maine was $14.18 U.S. calculated as follows:*

Weighted average crude oil f.o.b. source (mainly Venezuela and Middle East)	=	*$13.00 U.S./bbl.*
Ocean freight	=	*0.88*
Ocean loss	=	*0.05*
Portland pipeline tariff	=	*0.25*
		$14.18 U.S./bbl.

The quality of imported crude to eastern Canada is on average equivalent to 32.4° API gravity and 1.5% S. The quality of average crude oil delivered from Alberta to Toronto is estimated to be 37° API gravity and 0.3% S; the price of equivalent quality foreign crude imported to Montreal would be some $0.38 more than $16.68/bbl. or $17.06 Canadian/bbl. calculated as follows:

Gravity premium = $0.03/°API x 4.6°	=	*$0.138/bbl.*
Sulphur premium = $0.02/0.1%S x 1.2% S	=	*0.24*
		$0.378/bbl.

[3] *The Canadian oil price is assumed to increase $1.00/bbl. (current $) July 1, 1979 and $2.00/bbl./year (current $) in 1980 and afterwards until parity is reached with the international price. This equality is achieved in 1984 at a price of $17.10 Canadian/bbl. (1978$). The constant dollar price of Canadian oil is assumed to increase after 1984 in equal annual amounts to $20.00/bbl. (1978$) by 1990 and remain constant thereafter to 2000.*

4 Toronto city gate oil price in December 1978 calculated as follows:
Alberta field price* = $12.75/bbl.
Average gathering charge to Edmonton = 0.28
Interprovincial Pipeline tariff:
Canadian portion of pipeline*= 0.332
U.S. portion of pipeline** = 0.394 Canadian
Toronto city gate = $13.76 Canadian/bbl.

* $12.75/bbl. is price which applies to the average quality of all Alberta crudes.

** IPL U.S. pipeline tariff is $0.335 U.S./bbl. or $0.394/Canadian at exchange rate of $1.00 Canadian = $0.85 U.S.

5 Annual Canadian inflation rate of 6% per year assumed for purposes of converting current dollar prices to 1978$.

6 The December 1978 natural gas price was $2.00/MMBtu or 84.3% of the price of crude oil at Toronto.

TABLE 8: NATURAL GAS CITY GATE PRICES AND TRANSCANADA PIPELINE TARIFFS, CANADA, 1978-2000

(1978 $/MMBtu)

	Eastern Ont.		Northern Ont.		Western Ont.		Manitoba		Saskatchewan		Alberta
	TCPL[2] tariff	City-[3] Gate Price	TCPL[2] tariff	City-Gate Price	TCPL[2] tariff	City-Gate Price	TCPL[2] tariff	City Gate Price	TCPL[2] tariff	City-Gate Price	Border Price
Dec. '78[1]	0.59	2.00	0.47	1.88	0.30	1.71	0.18	1.59	0.04	1.45	1.41
1979	0.59	1.97	0.47	1.85	0.30	1.68	0.18	1.56	0.04	1.42	1.38
1980	0.60	2.12	0.48	2.00	0.30	1.82	0.18	1.70	0.04	1.56	1.52
1981	0.61	2.25	0.48	2.12	0.31	1.95	0.19	1.83	0.05	1.69	1.64
1982	0.61	2.35	0.49	2.20	0.31	2.02	0.19	1.90	0.05	1.76	1.71
1983	0.62	2.44	0.49	2.32	0.31	2.13	0.19	2.01	0.05	1.87	1.82
1984	0.62	2.50	0.50	2.38	0.31	2.19	0.19	2.07	0.05	1.93	1.88
1985	0.63	2.58	0.50	2.45	0.32	2.27	0.20	2.15	0.05	2.00	1.95
1986	0.63	2.65	0.51	2.53	0.32	2.34	0.20	2.22	0.05	2.07	2.02
1987	0.64	2.72	0.51	2.59	0.32	2.40	0.20	2.28	0.05	2.13	2.08
1988	0.64	2.79	0.51	2.66	0.32	2.47	0.20	2.35	0.05	2.20	2.15
1989	0.65	2.86	0.52	2.73	0.33	2.54	0.20	2.41	0.05	2.26	2.21
1990	0.65	2.93	0.52	2.80	0.33	2.61	0.20	2.48	0.05	2.33	2.28
1995	0.65	2.93	0.52	2.80	0.33	2.61	0.20	2.48	0.05	2.33	2.28
2000	0.65	2.93	0.52	2.80	0.33	2.61	0.20	2.48	0.05	2.33	2.28

[1] *TCPL tariffs calculated from National Energy Board, In The Matter of an Application Under Part IV of the National Energy Board Act (Rates Application) of TransCanada Pipelines Ltd., July 1978. Rates are calculated assuming a gas heating value of 995 Btu/cft. taken at 100% load factor.*

[2] *The TCPL tariff from the Alberta border to the Toronto city gate is forecast to remain constant at the December '78 level (1978$) except for increases of 1¢/MMBtu for every 14.65¢/MMBtu increase in the Toronto city gates price to account for cost of fuel increases.*

[3] *The Toronto city gate price from 1979 onwards assumed at 85% of the Toronto city gate Canadian crude oil price.*

The TCPL tariffs from the Alberta border to other rate zones are assumed to remain at the same proportion to the Eastern rate zone tariff as prevailed in December 1978, namely:

Northern Ontario = 79.8%
Western Ontario = 50.3%
Manitoba = 31.0%
Saskatchewan = 7.5%.

TABLE 9: INDUSTRIAL HEAVY FUEL OIL AND NATURAL GAS PRICES CANADA, 1978-2000

(1978 $/MMBtu)

	Heavy[1] Fuel Oil	Natural Gas[2]				
		Alberta	Sask.	Manitoba	Western Ontario	Northern Ontario
December '78	1.97	1.41	1.60	1.74	1.86	2.03
1979	1.92	1.38	1.57	1.71	1.83	2.00
1980	2.07	1.52	1.71	1.85	1.97	2.15
1981	2.19	1.64	1.84	1.98	2.10	2.27
1982	2.29	1.71	1.91	2.05	2.17	2.35
1983	2.38	1.82	2.02	2.16	2.28	2.47
1984	2.44	1.88	2.08	2.22	2.34	2.53
1985	2.51	1.95	2.15	2.30	2.42	2.60
1986	2.58	2.02	2.22	2.37	2.49	2.68
1987	2.65	2.08	2.28	2.43	2.55	2.74
1988	2.72	2.15	2.35	2.50	2.62	2.81
1989	2.79	2.21	2.41	2.56	2.69	2.88
1990	2.86	2.28	2.48	2.63	2.76	2.95
1995	2.86	2.28	2.48	2.63	2.76	2.95
2000	2.86	2.28	2.48	2.63	2.76	2.95

[1] *Heavy fuel oil price assumed at 90% of crude oil price on volumetric basis or 83% of crude price on Btu basis. These HFO prices assumed to apply to large industrial users in or near major centres in southern and eastern Ontario, Quebec, and the Maritimes; this relationship of HFO prices to the Canadian or Toronto city gate price is also forecast to prevail in the Vancouver area and on Vancouver Island.*

[2] *Natural gas prices to large industrial consumers from Saskatchewan through northern Ontario at 15¢/MMBtu above the city gate prices, approximately equal to the situation in December 1978. For Alberta, large industrial gas prices are assumed at 15¢/MMBtu above the Alberta border price, again an approximation of the pricing situation to most large industrial users in December 1978.*

relevant city gate price in each of the TCPL rate zones; in Alberta the large industrial natural gas price is forecast to equal the Alberta border price.

The natural gas price to the larger energy users in the General industrial category, who may be considered as potential coal users (see Chapter IV, 9.0), will be forecast at 30¢/MMBtu above the prevailing city gate natural gas price.* This category of demand will still include large users of fossil fuel energy but on average quantities consumed will be less than by customers discussed in the individual industrial categories such as pulp and paper, cement, etc. Delivered fuel oil prices to larger accounts in the General industrial sector will be estimated at 110% of the crude oil price on a Btu content basis.**

3.0 HOG FUEL

Wood residuals (hog fuel) such as sawmill waste and bark will become an increasingly important source of energy to the pulp and paper sector as fossil fuel prices increase.

Hog fuel does not generally yield a net-back price to the supplier; i.e. with arms-length transactions the buyer generally pays loading and transportation costs, but pays nothing extra for its value as a fuel. Suppliers, in making hog fuel available, save disposal costs that would otherwise be incurred: disposal costs range from a few cents per million Btu in burners to about 40¢/million Btu for landfills. With higher fossil fuel prices and the related increased demand for hog fuel a market price may evolve for more accessible supplies and particularly for the dryer shavings. For this analysis though it is assumed that hog fuel will continue to be available to buyers at cost. That portion of hog fuel generated within a single forestry company enterprise will certainly be available at a price equal to handling costs only.

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* *Industrial firm gas rate schedules of utilities from Alberta to Ontario for customers taking gas at 75% load factor and a minimum take of 100 Mcf/day range roughly from 20 to 30¢ of above city gate prices. A figure of 30¢/MMBtu will be used in this analysis.*

** *In first half 1978 the light fuel oil price to accounts of over 100,000 gallons/year in southern Ontario was approximately 40¢/gal. or $14.00/bbl. This was 10% greater than the then prevailing Toronto city gates crude price of approximately $12.75/bbl. This fuel price was reflective of a very price competitive time period between fuel oil and natural gas suppliers and among fuel oil dealers themselves.*

At fossil fuel prices prevailing during the latter half of 1977, one pulp mill operator in Ontario with hog fuel burning equipment calculated that hog fuel was competitive with other fuels if supplies were available within a 75 mile haul distance. In the future with further fossil price increases the zone of economically available supplies of hog fuel will expand.

The assumption in this study is that in each province with a pulp and paper industry, hog fuel will replace most of the fossil fuel component of this sector's energy requirements, to the extent that hog fuel supplies are forecast to be available. Specific assumptions concerning hog fuel availability and consumption are made in Chapter IV.

4.0 ELECTRIC ENERGY

The average price of electricity across Canada has risen approximately 40% over the 1975 to 1978 period in response to much higher capital costs of generating facilities and much higher plant operating costs, particularly fuel costs for thermal electric stations.* Continuing large price increases are expected in all provinces, at least in the short term. In Quebec for example the trailing rate for residential electric energy is currently 2.2¢/kwh ($4.25/MMBtu at gas efficiency of 0.65 vs. electricity); this will increase to 2.5¢/kwh January 1, 1980 and to 2.8¢/kwh in January 1, 1981 (27% price increase from January 1, 1979 to January 1, 1981). Quebec Hydro's trailing rate to residential accounts is higher than their "lighting and appliance" rate. The price in 1978 to large industrial users was about 1.5¢/kwh ($3.30/MMBtu, using a gas efficiency of 0.75 vs. electricity); this has increased to 1.8¢/kwh in 1979 (a 20% increase) and will increase further to 2.08¢/kwh in 1980 (39% over 1978) and to 2.34¢/kwh in 1981 (56% over 1978).*

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* *Centre for the Study of Inflation and Productivity, Quarterly Newsletter, Ottawa. As reported in the Calgary Herald February 24, 1979.*

A recent report commissioned by the Department of Energy, Mines and Resources forecast a continuation of significant electric energy price increases over the next 10 years.** Beyond that time the study suggests "price increases might moderate and the price of electricity become increasingly competitive with oil and natural gas for many uses."

Our assessment is that electricity rates in Canada will increase appreciably in real terms over the forecast period. A major factor in this assessment is the conviction that electric utilities will move to adjust their rate structure to more adequately reflect the cost of adding new capacity to their systems. A hearing into peak period and marginal cost pricing was commenced by the Ontario Energy Board in 1977, and should be completed in 1979. The outcome of this hearing will probably have an important bearing on the magnitude and rate of electric energy price increases across Canada.

Large industrial electric energy prices in all provinces are substantially above delivered fossil fuel prices. For example the Ontario Hydro rate in 1978 of 1.8¢/kwh* was equivalent to about $4.00/MMBtu (using an oil and natural gas efficiency factor of 0.75 vs. electricity) compared to the large industrial heavy fuel oil price in southern and eastern Ontario of about $2.00/MMBtu and the natural gas price of about $2.15/MMBtu. The assumption of this report is that electric energy prices to industrial customers will remain well above oil and natural gas prices over the forecast period in all areas. Under this assumption no significant shift in the fossil fuel vs. electric energy share of the industrial market is expected. Quebec is a possible exception; Quebec's domestic electric energy supply base is very large and may be used as an instrument of policy in attracting industrial enterprises to the province. Promotional pricing of electricity could be instituted in an effort to attract electric energy based activities to Quebec.

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* *Customer with 10,000 kwh/month contract demand at 75% load factor (load factor constant over 12 months). Hydro-Québec Bylaw No. 225 Establishing Electricity Rates and the Conditions of Their Application. January 1, 1979.*

** *James E. Gander and Fred W. Belaire, Energy Futures for Canadians, June 1978, p. 206.*

* *Customer with 10,000 kw/month contract demand at 75% load factor (load factor constant over 12 months).*

5.0 COAL PRICES

Coal will certainly have to sell at a discount from fuel oil and natural gas prices to be competitive in industrial applications. The additional costs associated with the use of coal as an industrial fuel will be dependent on 3 main factors:

1) The energy conversion system in use; that is whether energy is utilized in a steam generator, in direct firing systems, in process heaters, etc.
2) Whether the use of coal is being considered in new plant or in a replacement of existing facilities.
3) The form in which the coal energy is utilized, that is whether the coal is fired directly as a fuel or first converted to gaseous or liquid forms.

The discussion which follows develops discounts at which coal must sell, relative to prevailing oil and gas prices, if it is to be competitive in various end use applications.

5.1 Energy Conversion Systems and User Costs Associated With Coal Use

Energy is utilized in industry in a variety of combustion processes. The most common energy conversion systems are the following:

1) Steam generation.
2) Open firing.
3) Process heaters.
4) Chemical conversion (feedstock use).
5) Other (gas turbines, blast furnace injection, etc.).

5.1.1 Steam Generation

Most industrial fuel is utilized via steam generation processes. Steam systems have the widest flexibility for the substitution of alternative energy sources. Coal can be utilized in virtually all applications from a technological point of view; in some cases however, factors such as site space limitations or environmental regulations may rule out its use. Large economies of scale are present in direct coal fired steam systems both in the energy conversion system itself and in the delivered cost of the coal.

One generalized set of capital cost estimates, and annual operating and maintenance cost estimates is shown in Tables 10 and 11. Capital cost estimates for coal systems are seen to be over three times the costs for a natural gas plant; heavy fuel oil plants are 50% to 75% higher in cost than gas plants. Annual operating and maintenance costs are in the order of 10% of capital costs for all systems.

Using these cost factors the required coal price discount to make it competitive with heavy fuel oil and natural gas can vary from $0.94/MMBtu to $2.21/MMBtu depending on size of boiler considered (Table 12).

Existing industrial plants will need larger coal price discounts to justify scrapping existing equipment and installing coal fired equipment. In the most extreme comparison typical of a situation where the oil/gas boiler system to be replaced by coal has been newly installed, and where the capital cost associated with the gas/oil alternative is taken as zero, the coal price penalty associated with installing a coal system is seen to be roughly $0.30/MMBtu to $0.70/MMBtu higher than the new plant case for the range of cases studied (see Table 12).

5.1.2 Open Firing

In many industrial applications the manufactured product is heated in direct contact with the combustion gases. Examples of this type of operation would be gas fired ovens and melting furnaces common to the primary metals and glass industries, or in applications where products such as pulp and paper, potash, grain, etc. must be dried. Coal is not a feasible alternative in these uses because of contamination of the product with particulate matter or sulfur. In other open firing processes such as lime kilns, cement kilns, and sintering furnaces, coal use is an alternative to be considered. Where coal can be used in open firing applications, cost problems associated with its use are liable to be of a smaller magnitude than is the case in processes requiring the generation of steam. For cement and lime plants for example, conversion of the processes to coal use can be justified at a coal discount of \$0.21 to \$0.32/MMBtu (see Table 13 and 14).

TABLE 10: TOTAL CAPITAL COST OF ALTERNATIVE BOILER SYSTEMS[1, 2]
(1978$, thousands)

Boiler Type	Boiler System Size (M lbs./hr. steam)			
	50	100	200	400
Coal				
Bituminous[3]	4480	7370	12340	22100
Sub Bituminous[4]	4650	7660	12850	22970
Heavy Fuel Oil	2000	3200	5300	9340
Natural gas	1480	2260	3530	5960

[1] SOURCE: ICF Incorporated, Economic Considerations in Industrial Boiler Fuel Choice, Washington D.C., June 1978. Costs shown by ICF in 1977 U.S.$ have been escalated by 20% in total; by 10% to reflect increased costs expressed in 1978$ terms, and by an additional 10% as an estimate of the premium required to express costs in Canadian $ terms.

[2] *Capital costs include direct plus indirect costs. Direct costs include land, fuel handling and storage, boiler house and equipment, ash handling and particulate control equipment. SO_2 control equipment is not included; pollution control capital costs for coal units are reduced by 75% to reflect particulate control only.*
Indirect costs include construction management, design, contingency, working capital, and fuel stockpile cost.
Interest during construction is not included here but is explicitly included in the determination of the capital charge rate used to annualize the capital cost.

[3] *12,000 Btu/lb., 0.7% sulfur, and 12% ash.*

[4] *8500 Btu/lb. 0.5% sulfur, and 9% ash.*

[5] *Low sulfur, 0.3%.*

TABLE 11: TOTAL ANNUAL OPERATING AND MAINTENANCE COSTS[1, 2] OF ALTERNATIVE BOILER SYSTEMS (1978$, thousands)

Boiler Type	Boiler System Size (M lbs./hr. steam)			
	50	100	200	400
Coal				
Bituminous	375	640	1090	1970
Sub Bituminous	375	640	1090	1970
Heavy Fuel Oil	190	310	515	855
Natural Gas	145	235	385	630

[1] SOURCE: ICF Incorporated, op. cit., Chapter III. Costs are shown by ICF in 1977 $ and are escalated here by 20% to express costs in 1978$ Canadian.

[2] *Operation and maintenance costs include staff, maintenance materials, pollutant disposal, supplies and expenses, and administration. O&M costs shown by ICF for coal systems have been reduced by 25% to reflect the assumption that flue gas desulfurization is not included in the plant design. O&M figures are calculated on the basis of a 55% capacity factor.*
O&M cost does not include fuel cost.

TABLE 12: COMPARISON OF ANNUALIZED CAPITAL AND OPERATING COSTS OF ALTERNATIVE BOILER SYSTEMS

Boiler Type	Boiler Size (M lb./hr. steam) 50	100	200	400
Coal[1] (M 1978$)				
Total Capital Cost	4,500	7,500	12,500	22,500
Annualized capital cost[2]	765	1,275	2,125	3,825
Annual O&M cost	375	640	1,090	1,970
Total annual cost	1,130	1,915	3,215	5,795
Heavy Fuel Oil (M 1978$)				
Total Capital Cost	2,000	3,200	5,300	9,340
Annualized capital cost	340	544	901	1,588
Annual O&M Cost	190	310	515	855
Total annual cost	530	854	1,416	2,443
Natural Gas (M 1978$)				
Total Capital Cost	1,480	2,260	3,530	5,960
Annualized capital cost	251	385	600	1,013
Annual O&M cost	145	235	385	630
Total annual cost	396	620	985	1,643
Annual Cost Difference (M 1978$)				
New Plant				
Coal vs. oil	600	1,061	1,799	3,352
Coal vs. gas	734	1,295	2,230	4,152
Replacement Plant[3]				
Coal vs. oil	940	1,605	2,700	4,940
Coal vs. gas	985	1,680	2,830	5,165
Annual Energy Input[4] (10^9 Btu)	445	890	1,780	3,560
Required Coal Discount ($/MMBtu)				
New Plant				
Coal vs. oil	1.35	1.19	1.01	0.94
Coal vs. gas	1.65	1.46	1.25	1.17
Replacement Plant				
Coal vs. oil	2.11	1.80	1.52	1.39
Coal vs. gas	2.21	1.89	1.59	1.45

1 As costs of bituminous and sub bituminous systems are so close (Tables 10 and 11) a single coal figure is used which is the average of the bituminous and sub bituminous figures.

2 A real annual capital charge rate (1978$) of 17 percent is used. This rate translates all of the lifetime capital charges into a constant stream of annual fixed costs. This capital charge is based on a 20 year plant life, 10% return on debt, 15% after tax return on equity, a 50/50 debt/equity ratio, and a 50% corporate tax rate.

See ICF Inc., "Economic Considerations in Industrial Boiler Fuel Choice", Appendix C for the rationale behind the derivation of the capital charge rate.

3 Assumes the case where no capital cost of facilities is charged against the oil/gas installation as would be the case if such units were newly installed.

4 Boiler operating at annual capacity of 75%, e.g. 200,000 lb/hr. boiler:

$$\text{Annual output} = 200{,}000\ \text{lb/hr.} \times 8760\ \frac{\text{hrs.}}{\text{yr.}} \times 0.75 = 1{,}314 \times 10^6\ \text{lbs/yr.}$$

$$\text{Energy content} = 1314 \times 10^6\ \frac{\text{lb.}}{\text{yr.}} \times 1152\ \frac{\text{Btu}}{\text{lb.}} = 1{,}513 \times 10^9\ \text{Btu/yr.}$$

Boiler efficiency = 85%.

$$\text{Input energy} = \frac{1{,}513 \times 10^9}{0.85}\ \text{Btu} = 1{,}780\ \text{Btu/yr.}$$

TABLE 13: CEMENT PLANT COAL CONVERSION COSTS

Assumptions:

Plant size : 1 million tons per year(1)

Fossil fuel use: 4.66 MM Btu/ton(2)

	Case 1	Case 2
1. Capital cost of coal conversion(3)	\$3.00/ton	\$6.00/ton
Total conversion cost	\$3 million	\$6 million
Annual capital cost @ 17%	\$510,000	\$1,020,000
Annual fossil fuel use	4.66×10^{12} Btu	4.66×10^{12} Btu
Conversion capital cost/MM Btu	\$0.11	\$0.22
Incremental operating cost/MM Btu(4)	\$0.10	\$0.10
Total conversion cost/MM Btu	\$0.21	\$0.32

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(1) Considered to be a representative plant size.

(2) Based upon 1976 average energy intensity for Canadian-produced cement and clinker.

(3) Representative range of conversion costs based on the capital cost of recent plant conversions in the U.S. as reported in recent issues of Pit and Quarry and the U.S. Minerals Yearbook and related to plant capacities. Capital cost figures inflated at 10% per annum to convert to 1978 dollars.

(4) Industry source.

TABLE 14: LIME PLANT CONVERSION COSTS

Assumptions:

Plant size : 100,000 tons per year
Fossil fuel use: 5.5 MM Btu/ton(1)

Capital cost of coal conversion(2)	$500,000
Annual capital costs @ 17%	$ 85,000
Annual fossil fuel use	550×10^9 Btu
Conversion cost/MM Btu	$0.15
Incremental operating cost/MM Btu(3)	$0.10
Total conversion cost/MM Btu	$0.25

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(1) Based upon average fossil fuel use/ton in Canadian lime industry during 1976.

(2) Industry source. This calculation includes only the cost of coal handling and firing equipment; in some cases additional land and truckage may be required, increasing the total cost of conversion. A second lime producer indicated that his firm would consider conversion to coal at a price differential in the order of $0.40/MM Btu.

(3) Industry source.

5.1.3 Process Heaters

This category of energy conversion system is typified by the tubed furnace common to the petroleum industry or the pyrolysis units and in the chemical industry. As the manufactured product is not in open contact with the combustion gases, coal can be used as an energy source.

No cost figures are available to us on the cost of coal fired vs. oil/gas fired process heaters. We assume that the cost differences in terms of \$/MMBtu of input energy will be in the same order as for steam generator systems. A process heater designed for coal use will, similar to the case in boiler design, be much larger than an equivalent oil/gas unit; similarly process heaters using coal, in common with boiler systems, will require that associated facilities such as coal and ash handling equipment, stack precipitators, etc. be provided. It seems reasonable to conclude therefore that extra costs associated with coal using process heaters will be similar to the extra costs incurred by the use of coal steam generators, for units of comparable size.

5.1.4 Other

Specialized industrial energy conversion systems include such technologies as gas turbines and blast furnaces. The possible use of thermal coal as a blast furnace fuel is discussed in the steel section below (Chapter IV). Coal is considered to be an unsuitable fuel for direct firing in gas turbine applications because of particulate matter and the possibility of sulfur compounds in the combustion gases. The gasification or liquefaction of coal prior to combustion could make it acceptable for use in gas turbines and in other applications where it would not otherwise be considered.

5.1.5 Coal Gasification

Conversion of the coal to a low or medium Btu gas prior to use is to be considered, particularly in smaller use applications where the cost of direct coal fired systems would be very high or in those cases where clean combustion gases are required. Energy users in the "General Industrial" category described in Chapter IV below are typically smaller users of fossil fuel energy and often employ open firing processes requiring a clean combustion gas.

Commercial coal gasification processes are available today for producing low or intermediate Btu gas on a small scale - say 1 MMcf/d minimum. In the Wellman-Galusha process coal, steam, and air are fed into a revolving grate gasifier operating at atmospheric pressure and 1200°F to produce 150 Btu/cft fuel gas; fuel gas of 250 to 300 Btu/cft would be produced with air replacement by 60% to 100% oxygen. The Winkler process is a fluidized bed gasifier which also produces low or intermediate Btu gas from a wide variety of coals; reactor conditions are atmospheric pressures and temperatures of 1500° to 1800°F. Many commercial applications of the above technologies are in use outside of Canada. Based on very limited cost information the gasification costs of such systems have been calculated to range from $1.50 to $2.50/MM Btu's, including all capital ammortization costs and operating costs but exclusive of coal costs. The lower end of the range would apply to raw gas and the higher end to clean gas. The hot raw gas manufactured by the "producer" contains vaporized coal tar, hydrogen sulfide, cyanide, and perhaps some phenol and is suitable for use as a fuel provided these constituents can be tolerated; raw gas has a potential use in such applications as:

- iron and steel making
- brick, clay, ceramics manufacture
- glass making
- lime calcining
- sintering light weight aggregates
- sintering metals.

There is a most noticeable capital cost difference between raw gas and clean gas manufacture. This is due to the large additional amount of plant required to remove H_2S, tars, and other impurities from the gas stream. For many users such as the following clean gas is required:

- space heating
- powder (e.g. milk) manufacture
- drying: tobacco
    - bakeries
    - heat treating
    - paper and newsprint
    - grain
    - paint curing
    - etc.

Gasification of coal requires an input of 1.25 MMBtu of coal per 1.0 MMBtu of gas output.

CHAPTER IV

INDUSTRIAL COAL MARKETS

This chapter provides an analysis and forecast of the potential thermal coal demand of Canadian industries for the period to the year 2000. A number of energy intensive industries which are responsible for consumption of large volumes of energy are given individual consideration, with future energy requirements being related to anticipated future output levels, technological changes in energy intensiveness, and the impact of conservation measures. A residual industrial sector, "general industrial", covers all industrial activities which are not given individual consideration.

The general methodology of the analysis for each industrial sector involves:

(i) assessment of future energy requirements of the sector;

(ii) assessment of the proportion of energy requirements which could reasonably be supplied by coal;

(iii) assessment of the required discount in coal price per million Btu's relative to alternative fuel types in order for coal to capture the market. Generally the market is divided into components representing conversion and new installation situations (as outlined in Chapter III) as the required discounts differ.

Potential coal demand at various discount levels is allocated on a provincial or regional basis. This allows use of transportation cost information in Chapter VI, in conjunction with the forecast of competing energy prices in Chapter III, in order to determine the net-backs which would be available to coal mines in major Canadian coal mining areas from various components of the industrial market. A net-back analysis for 1990 and 2000 is provided in this report as Chapter VII.

Preparation of this chapter involved discussion with representatives of all industrial groups which are given individual consideration (Appendix A). Discussions covered matters such as expectations for future output, reasons for present fuel choice, past experience with coal, current assessment of the probability of future coal use, and expectations concerning process and conservation technology. Discussion material is supplemented, as noted in the text, by publications and material from individuals, companies, regulatory agencies, industrial associations and government agencies.

1.0 PULP AND PAPER

1.1 Introduction

The pulp and paper industry is one of the largest energy-using sectors in Canada, with the main concentrations of capacity located in Quebec, British Columbia, and Ontario. In order to forecast the potential for coal use in this industry, output in each producing area was first projected. In the absence of regional forecasts, a pulp and paper consumption study to 1990 prepared by the FAO* was adopted as the basis for projecting output in the pulp and paper industry, subject to the ability of the wood supply of each province to sustain increased levels of output. The latter assessment was made on the basis of a recent study which included an analysis of Canada's timber reserve.** Projected output was then multiplied by an energy requirement per ton of output, taking into consideration possible improvement in process efficiency and the substitution of less energy-intensive raw materials. Potential coal requirements were ultimately calculated as a residual by subtracting the quantity of energy likely to be available from wood wastes from the portion of total energy requirements substitutable by coal.

1.2 Interfuel Substitution

Before proceeding to discuss the potential for coal use in the pulp and paper industry at the provincial level, the applications in which coal and hog fuel (wood waste) are substitutable

* *Industry Working Party, Forestry Department of the Food and Agricultural Organization (FAO) of the United Nations, FAO World Pulp and Paper Consumption Outlook, September 1977.*

** *F.L.C. Reed & Associates Ltd., Forest Management in Canada, Vol. 1, Forest Management Institute, Information Report FMR-X-102, January 1978.*

and the range of price discounts required to justify such substitutions should be briefly examined. Generally speaking, three main types of end-use energy are required in this industry: electricity, for process drive and lighting; steam, for process heat, and, to a lesser extent, self-generation of electricity and process drive; and high-temperature combustion gases, for the calcining of lime in the kraft process. Coal is not directly substitutable in applications requiring electricity, and while it is used in large-scale lime kilns, coal is presently considered to be inappropriate for firing kraft mill lime kilns, reportedly due to problems with contamination of the lime produced. Fuel oil and natural gas are currently the only fuels used in kraft mill lime kilns, at the rate of about 2.5 million Btu's per ton of pulp. While experimentation is now being carried out at MacMillan Bloedel's Port Alberni operation in an attempt to develop technology to use wood wastes in lime kilns, the use of wood wastes for this purpose is yet unproven on a commercial scale.

Although coal and hog fuel are not presently considered to be substitutable in lime kilns, they are both proven fuels for raising steam in pulp mill power boilers, which are the largest consumers of purchased energy in the pulp and paper industry. Steam requirements vary widely, depending upon the type of product and efficiency of the individual mill, ranging from a low of 7 million Btu/ton of newsprint in a modern thermomechanical mill, about 10.5 million Btu/ton of kraft (if 50 percent of the electrical requirements are self-generated), to a high of more than 16 million Btu/ton of fine papers in an older mill.*

* *Council of Forest Industries (COFI) of B.C., The Forest Products Industry in B.C., submission to the B.C. Energy Commission 1978 Oil and Natural Gas Price Inquiry. May 1978, p. 55; Canadian Resourcecon Ltd., Forecast of Industrial Natural Gas Demand in Ontario and Quebec, 1976-2000, June 1978, p. 40.*

While either coal and hog fuel can be used to supply all the power boiler fuel requirements under ideal operating conditions, in practice either oil or gas is required as a supplemental fuel for start-up, flame stabilization, quick response to increased steam demand, and standby during outages of coal or hog fuel handling equipment. It is expected that, on the average, no more than 85 percent of power boiler steam output will be generated from hog fuel, or 90 percent from coal, with the remainder derived from oil or natural gas.

The derivation of conversion costs and price discounts required to justify the use of coal in a typical size pulp mill boiler of 400,000 lbs/hr is detailed in Chapter III, Section 5.0. For bituminous coal it is estimated that a discount of about $1.40 per million Btu's will be required to justify the conversion of existing oil or gas-fired boilers to coal use, while in new installations a smaller discount of about $1.00 per million Btu's is considered adequate to justify the choice of a coal-fired boiler in preference to an oil or gas-fired unit. Where coal-firing facilities already exist, the incremental operation and maintenance costs associated with using coal, as opposed to oil or gas, are estimated to be about 25¢/million Btu's.

Many pulp mills in Canada already possess the ability to generate a substantial portion of their power boiler steam requirements from hog fuel, but would require a new boiler especially designed for hog fuel in order to burn more than presently used. While the cost of boiler conversion is fairly site-specific, Table 15 presents an estimate of the discount required to install a hog fuel boiler as a replacement for an existing oil or gas-fired unit.

TABLE 15: ESTIMATED CONVERSION COSTS FOR HOG FUEL BOILERS (1978$)

Boiler capacity	450,000 lbs./hr.
Capital cost	$22 million
Annual costs	
capital charges at 15%	$3.3 million/yr.
incremental operation and maintenance	$1.0 million/yr.
Total	$4.3 million/yr.
Annual steam production at 67% capacity factor, 1152 Btu/lb.	3.04×10^{12} Btu/yr.
Annual fuel requirement (oil or gas) @ 80% efficiency	3.80×10^{12} Btu
Fossil fuel displaced by wood 85% wood, 15% gas or oil	3.23×10^{12} Btu
Cost of fossil fuel	$2.00/MMBtu
Cost of displacing fossil fuel	$1.33/MMBtu
Value of hog fuel (fossil fuel equivalent)	$0.67/MMBtu
or	$9.05/oven-dried ton

SOURCE: Canadian Resourcecon Limited.

In late 1978 the price of heavy fuel oil or natural gas was on the order of $2.00/MMBtu. If the discount required to justify the installation of a hog fuel boiler is $1.33/MMBtu, as calculated in Table 15, then the mill could pay up to 67¢/MMBtu for hog fuel, in fossil fuel equivalent terms. Given a gross heating value of 18 million Btu/oven-dried ton (ODT) and a hog fuel boiler efficiency of 60 percent versus 80 percent for fossil fuel boilers, the value of hog fuel is in the order of $9.05 per oven-dried ton at present.

As part of a renewable energy incentive program started last year, the federal government has agreed to provide up to 20 percent of the capital cost of equipment using wood wastes as a fuel source. Hence, the required discount for hog fuel could be as low as $1.13/MMBtu, increasing the value of hog fuel to 87¢/MMBtu, or $11.75/ODT. At present, most sawmills generating residues in excess of their own energy needs do not charge pulp mills for them, since it rids the sawmills of a disposal problem. In British Columbia, hog fuel is moved by barge from the concentration of sawmilling capacity on the Fraser River delta to pulp mills on Howe Sound and Vancouver Island up to 125 miles away. It is estimated that the economic hauling distance for transporting hog fuel by truck is now about 75 miles.*

Further escalations in the price of fossil fuels will serve to increase the economic hauling distance of hog fuel, bringing much of the currently unutilized supply within economic reach of the pulp and paper industry. It is postulated that such a trend, combined with government incentives to exploit renewable energy sources, will result in pulp mills fully utilizing available mill residues to displace oil and natural gas, with coal competing for the substitutable portion of residual fossil fuel demand.

1.3 Process Efficiency

Given the variety of processes used in the manufacture of pulp and paper products, and the length of the forecast period, it is difficult to gauge the overall potential for improvements in process efficiency with any degree of accuracy. The pulp and paper energy task force has set a goal of reducing purchased energy use per ton of product by 12 percent from 1972 to 1980. It appears likely that this reduction will, in fact, be attained on schedule, according to the Canadian Pulp and Paper Association which monitors energy use in the industry. Not all of the reduction in purchased energy requirements, however, will be due to improvements in process efficiency. It will also result from the substitution of hog fuel for fossil fuels.

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* *Abitibi Paper Company, personal communication.*

Process efficiency improvements in the short term will largely be in the form of housekeeping measures to reduce heat losses. Over the longer term, more capital intensive measures involving basic changes in process technology will be necessary to achieve further gains in efficiency.

It might be expected that increasingly stringent pollution control regulations would reduce process efficiency, but this is not necessarily the case. The Great Lakes Paper Company, for example, has incorporated the Rapson effluent-free process in its bleached kraft mill at Thunder Bay. This process is claimed to virtually eliminate biochemical oxygen demand, suspended solids, and colour in the mill effluent, while reducing process steam requirements by almost 4 million Btu per ton of pulp.* It has also been reported that the Rapson process can be retrofitted into existing kraft mills, a capability which would benefit the Canadian industry in view of the limited prospects for new capacity over the forecast period.

1.4 Materials Substitution

The increased use of recycled fibre can also be expected to reduce the energy requirements of paper and paperboard over the forecast period. In the FAO study, waste fibre is forecast to increase from 6.4 percent of total fibre furnish for Canadian paper and paperboard in 1972 to 1974 to 9.6 percent by 1990. At this rate of growth, waste fibre would constitute more than 12 percent of total fibre input by the end of the forecast period - a modest but noteworthy increase.

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* *Skovronek, op.cit.*

In combination, it is estimated that improvements in process efficiency and increased recycling will reduce the overall steam requirement per unit of output by 15 percent from 1975 to the year 2000, a decrease of about 0.6 percent per annum. By comparison, the pulp and paper energy task force goal of a 12 percent reduction in purchased energy use per unit of output from 1972-1980, translates into an average annual decrease of about 1.6 percent.

1.5 Regional Analysis of Coal Markets

1.5.1 Ontario

(a) Industry Structure and Output

(i) Present Industry Structure and Historical Output

The Ontario pulp and paper industry, comprised of 39 mills in 1976, is quite integrated, with most of the wood pulp being upgraded to paper products within the province prior to export. There are 20 integrated pulp and paper mills, 15 paper mills, and 4 pulp mills in Ontario.* Nearly all of the large-scale pulp and newsprint mills are located in the northern part of the province, close to timber supplies, while mills in the south are largely restricted to the production of specialized paper and paperboard products and are generally of a much smaller scale.

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* *Canadian Pulp and Paper Association, 1977 Reference Tables, p. 6.*

Newsprint has historically been the most important product group, accounting for about 55 percent of total paper and paperboard production in recent years. Most newsprint produced in Ontario goes to U.S. market. Printing and writing paper and paperboard, on the other hand, are primarily oriented to the Canadian market.

Tables 16 and 17 show Ontario pulp and paper production in recent years. In 1975 a strike in the industry dramatically reduced output from peak production levels in 1974. A continuation of the strike into 1976, combined with depressed market conditions during the past two years, has kept output of pulp and paper products below 1974 levels. Virtually all groundwood pulp and most sulphite pulp is used within Ontario mills in the production of newsprint. A large proportion of the sulphate (kraft) pulp produced in Ontario, on the other hand, is exported directly as pulp for conversion to paper elsewhere.

Over the three year period, 1972 to 1974, estimated pulp exports from Ontario averaged just under 1,000 tons per year. If estimated exports are added to total paper and paperboard production during the same period, the combined totals exceed pulp production by about 10 percent. This apparent anomaly is explained by the fact that, in addition to wood pulps, significant amounts of recycled waste paper, fillers, and pigments are used in the production of paper and paperboards. Kraft pulp has accounted for more than 90 percent of pulp exports from Ontario in recent years.

Total pulp and paper production in Ontario, as calculated in Table 18, increased at an average annual rate of 2.8 percent over the 10 year period, 1964 to 1974, with paper and paperboard, rather than export pulp, accounting for the bulk of the increase.

TABLE 16: ONTARIO PULP PRODUCTION BY TYPE

(000 Tons)

Year	Groundwood	%	Sulphate	%	Sulphite	%	Other	%	Total
1964	1,513	46	848	26	736	22	221	7	3,318
1965	1,539	46	848	25	746	22	224	7	3,357
1966	1,625	45	1,038	29	707	20	217	6	3,587
1967	1,602	44	1,122	31	689	19	206	6	3,619
1968	1,548	42	1,238	34	653	18	205	6	3,644
1969	1,729	44	1,328	34	700	18	204	5	3,961
1970	1,683	42	1,368	34	703	18	215	5	3,969
1971	1,648	43	1,321	35	628	17	203	5	3,800
1972	1,610	41	1,521	39	589	15	217	6	3,937
1973	1,686	42	1,541	38	613	15	204	6	4,044
1974	1,746	41	1,624	38	631	15	273	6	4,274
1975 (1)	714	26	1,210	43	676	24	200	7	2,800
1976									3,373
1977 (2)									3,977

SOURCE: Statistics Canada, unpublished data.

(1) Reduced production levels in 1975 were due to a strike which carried on into 1976.

(2) Pulp production by type not available for these years.

TABLE 17: ONTARIO PAPER AND PAPERBOARD PRODUCTION

(000 Tons)

Year	Newsprint	%	Printing & Writing Paper	%	Other Paper & Paperboard	%	Total Paper & Paperboard
1964	1,714.2	62	323.0	12	731.2	26	2,768.4
1965	1,734.4	62	344.7	12	740.0	26	2,819.1
1966	1,848.9	62	420.9	14	700.4	24	2,980.2
1967	1,815.8	62	424.4	14	706.3	24	2,946.5
1968	1,759.8	60	447.7	15	745.6	25	2,953.1
1969	1,923.8	60	469.4	15	788.5	25	3,181.7
1970	1,857.6	58	532.6	17	787.8	25	3,178.0
1971	1,773.6	57	513.6	16	831.8	27	3,119.0
1972	1,790.5	55	561.7	17	883.1	27	3,235.3
1973	1,950.2	55	573.1	16	1,039.3	29	3,562.6
1974	1,960.1	52	698.3	19	1,093.6	29	3,752.0
1975	1,256.9	54	408.0	18	649.2	28	2,314.1
1976	1,555	54	492	17	810	28	2,857
1977	1,773(1)	55	548(2)	17	903(2)	28	3,224(2)

SOURCE: 1972-76 Statistics Canada, Catalogue 36-204, Pulp and Paper Mills.

(1) Canadian Pulp and Paper Association. Statistics Canada and CPPA newsprint production figures have been virtually identical in recent years.

(2) Estimated on basis of average proportional relationships among product groups during five-year period, 1971-76.

TABLE 18: ONTARIO PULP EXPORTS AND TOTAL PULP AND PAPER PRODUCTION

(000 Tons)

Year	Pulp Produced	Pulp Used	Pulp Exports[1]	Paper and Paperboard	Total Pulp and Paper Production
1964	3,317	2,493	824	2,768	3,592
1965	3,357	2,611	746	2,819	3,565
1966	3,587	2,755	832	2,980	3,812
1967	3,619	2,750	869	2,947	3,816
1968	3,644	2,725	919	2,953	3,872
1969	3,961	2,948	1,013	3,182	4,195
1970	3,969	2,946	2,023	3,178	4,201
1971	3,800	2,843	957	3,119	4,076
1972	3,937	2,869	1,069	3,235	4,304
1973	4,044	3,117	927	3,563	4,490
1974	4,274	3,287	987	3,752	4,739
1975	2,800	2,051	762[2]	2,314	3,076
1976	3,285	-	777[2]	2,857	3,634
1977	3,977	-	967[2]	3,224[3]	4,191

SOURCE: Statistics Canada, Catalogue 36-204, Pulp and Ppaer Mills.

(1) Pulp produced - pulp used.

(2) Actual export figures obtained from Statistics Canada export printouts.

(3) Estimate from Table 16.

(ii) Future Output

There is virtually unanimous agreement Canada's pulp and paper industry will grow much less rapidly in the future than it did during the 1960's and early 1970's. Canada's competitive position in world export markets is expected to deteriorate for a number of reasons. A recent sector profile of the Canadian forest industry* indicates that overall manufacturing costs for newsprint and bleached kraft pulp, while constitutes virtually all of Ontario's exports, are significantly lower in the southern U.S. than in eastern Canada. In addition, Canadian producers are often faced with higher costs in transporting their products to U.S. markets. Sharply increased pulpwood costs pose the most significant disadvantage to Ontario pulp and paper mills. In 1976 delivered pulpwood costs in Ontario were in the vicinity of $60 to $90 per cunit, compared to $45 to $55 in the southern U.S., and $25 to $40 in Brazil.**

The United States is expected to increase its degree of self-sufficiency in newsprint over the forecast period, while Eastern Europe and Latin America will probably become completely self-sufficient.*** Hence, the Ontario newsprint industry is likely to experience much lower rates of growth in traditional U.S. markets, while prospects for expanding into alternate markets are not good.

There is also some concern that Brazilian market pulp exports, which are expected to reach 1.2 million tons per year by 1979, could undercut Canadian pulp in U.S. markets if the U.S. economy and pulp demand are weak.**** Production of printing and writing papers and paperboards, which are oriented to domestic Canadian markets, will probably increase at a slower rate than in the past but at a higher rate than newsprint, provided that Canadian tariff barriers are maintained.

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* *Industry, Trade and Commerce, Canada, Sector Profile: The Canadian Forest Products Industry, 1977.*

** *Industry, Trade and Commerce, Canada, op.cit., p. 8.*

*** *Canadian Forest Industries, May 1977, p. 42.*

**** *Canadian Pulp and Paper Industry, July 5, 1977, p. 9.*

A pulp and paper consumption study to 1990 recently prepared by FAO* has been adopted herein as the basis for forecasting output in the Ontario pulp and paper industry. Since 1975 and 1976 were not representative production years in Canada due to strikes, the FAO study uses the average production of the three-year period, 1972 to 1974 as a base for projecting production from 1975 to 1990. It is forecast that production of Ontario pulp and paper output in aggregate will grow at the same rate forecast for total paper and paperboard in Canada as a whole by the FAO group, and that this rate will prevail until the year 2000.

From 1972 to 1974 total pulp and paper production in Ontario averaged about 4,511 thousand tons per annum. Given the average growth rate of about 1.4 percent per annum forecast by the FAO, Ontario output is projected as shown in Table 19 below. It is expected that kraft pulp will increase its proportion of total pulp and paper production from about 34 percent in 1974 to 50 percent in 1990 and thereafter, as sulphite pulp capacity is retired and replaced with kraft capacity. Forecast kraft output is detailed in Table 19 for the purpose of projecting the quantity of energy requirements in which coal is considered non-substitutable.

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* *Industry Working Party, Forestry Dept. of the Food and Agricultural Organization (FAO) of the United Nations. FAO World Pulp and Paper Consumption Outlook, September 1977.*

TABLE 19: FORECAST OUTPUT OF THE ONTARIO PULP AND PAPER INDUSTRY
(million Tons)

Year	Total Pulp and Paper	Kraft Pulp
1972-74 ave.	4.5	1.6
1980	4.8	1.9
1985	5.2	2.3
1990	5.6	2.8
1995	6.0	3.0
2000	6.4	3.2

(b) Energy Use

(i) Past and Present

During the decade of 1964 to 1974, natural gas displaced coal as the major source of fossil fuel energy as shown in Table 20.

TABLE 20: FOSSIL FUEL ENERGY USE IN ONTARIO PULP AND PAPER MILLS 1964 and 1974(1)

	1964		1974	
	10^9 Btu	%	10^9 Btu	%
Natural gas	21,496	42	44,558	69
Fuel oil	5,580	11	14,117	22
Coal	24,223	47	6,044	9
Total	51,299	100	64,779	100

SOURCE: Central Statistical Services, Consumption of Fuel and Electricity by Ontario Manufacturing Industries; Acres Consulting Services Ltd., Ontario Industrial Energy Demand Study, Ontario Ministry of Energy, 1977.

(1) 1974 is used in this analysis as it is considered to be more representative than 1975, a year when Ontario pulp mills operated at only about 60 percent of rated capacity due to a strike shutdown.

The change from coal to natural gas use in Ontario pulp and paper mills during this period has been attributed to a number of factors, including: new pollution regulations, labour costs in coal boiler operation, high capital cost of coal handling systems, and low and stable natural gas prices in contrast to rapidly rising coal prices.* At present 11 Ontario pulp and paper mills have the capability to burn coal, but largely as a standby fuel during periods of natural gas supply interruption.**

In the northwestern region, the Kenora mill of Ontario-Minnesota burns about 180 tons of coal per day in addition to natural gas, while Reed Paper at Dryden uses an unspecified amount of coal on a standby basis.*** Saskatchewan lignite is reportedly available to mills in this area at a much lower cost than natural gas.

Farther east, mills at Thunder Bay, Marathon, and Sault Ste. Marie currently obtain bituminous coal from American suppliers by lake boat. The choice of American coal in preference to Saskatchewan lignite may, in part, reflect the costs of the longer rail haul to Thunder Bay. However, it is more likely a result of the fact that boilers designed to burn concentrated fuels such as bituminous coal, natural gas, and fuel oil, cannot produce an equivalent amount of steam from low-Btu lignite. Therefore, lignite is not likely to be used in existing boilers unless they were specifically designed for that fuel.

Coal is also burned by mills in the Iroquois Falls-Kapuskasing area of northeastern Ontario as a standby fuel during periods of natural gas interruption.

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* *Ontario Hydro, Energy Use in the Pulp and Paper Mills in Ontario, Report PMA 74-11, October 1974, p. 19.*

** *1978 Post's Pulp and Paper Directory.*

*** *Ibid.*

Ontario pulp and paper mills also generate a significant and growing proportion of their process steam from waste burning. In 1972 it was estimated that about 9,636 x 10^9 Btu of process steam were generated from black liquor solids in kraft mill recovery boilers, while the burning of bark contributed 1,854 x 10^9 Btu, for a combined total of about 11,490 x 10^9 Btu.* Since 1972, many Ontario mills have significantly increased their bark-burning capability, including Abitibi at Smooth Rock Falls, Ontario-Minnesota at Kenora, and Great Lakes Paper Company at Thunder Bay. Hog fuel use during 1974 was in the vicinity of 300,000 oven-dried (O.D.) tons.** Assuming a gross heating value of about 18 million Btu/O.D. ton and an average boiler conversion efficiency of 60 percent (at 50 percent bark moisture content), about 3,240 x 10^9 Btu of process steam were generated from hog fuel during 1974, equivalent to about 4,050 x 10^9 Btu's of fossil fuels.

With the exception of mills at Fort Francis and Thunder Bay, all of the other 14 major pulp and paper mills in northern Ontario have the ability to burn at least one alternate fuel in addition to oil or natural gas. Of these 14 mills, 11 have the ability to burn hog fuel, 10 can use coal, and 8 can burn both hog fuel and coal.*** The paper mills in southern Ontario, on the other hand, use oil or gas almost exclusively due to their much lower process heat requirements per ton of product and smaller scale operation. As oil and natural gas prices continue to increase in real terms over the forecast period, it is expected that these efforts will be intensified.

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* *Ontario Hydro, op.cit., Appendix B.*

** *Canadian Pulp and Paper Association, Personal communication, March 1978.*

*** *1978 Post's Pulp and Paper Directory.*

(ii) Future Energy Use

During 1974, about 64.8 x 10^{12} Btu of fossil fuels and 4.1 x 10^{12} Btu of hog fuel (on a fossil fuel equivalent basis) for a total of 68.9 x 10^{12} Btu, were used as process heat sources in Ontario pulp and paper mills. Given an output of 4.7 million tons during the same year, energy requirements work out to about 14.7 million Btu/ton of pulp and paper production. This aggregate energy coefficient, combined with the projections of future output and energy conservation possibilities detailed earlier in this section, is used to forecast total fuel requirements in the Ontario pulp and paper industry as shown in Table 21.

A number of deductions from the total fuel requirements forecast in Table 21 must be made in order to calculate the residual process heat requirement in which coal is substitutable. These include: an allowance of 2.5 million Btu/ton of sulphate pulp for non-substitutable oil and gas use in lime kilns; the fossil fuel equivalent of process heat provided by hog fuel plus an allowance (15 percent) for supplemental oil and gas requirements in mills burning hog fuel; and an allowance (10 percent) for supplemental oil or gas requirements in mills using coal as a power boiler fuel.

It has been estimated that about 1,500,000 O.D. tons of mill residue are currently unutilized in Ontario. If all bush residues including tops, branches and cull species were utilized, about 10 million O.D. tons of residues would be physically available at present levels of harvest, and 20 million O.D. tons if the total allowable annual cut were reached.* Much of

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* *Raw Materials Task Force, Candidate Raw Materials for the Production of Synthetic Liquid Fuels in Ontario, Ontario Ministry of Natural Resources, October, 1977.*

TABLE 21: FORECAST FUEL REQUIREMENTS, ONTARIO PULP AND PAPER INDUSTRY(1)

Year	Output	Fuel per Unit of Output (2)	Total Fuel Requirements
	10^6 tons	10^6 Btu/ton	10^{12} Btu
1974(3)	4.7	14.7	68.9
1980	4.8	14.3	67.2
1985	5.2	13.8	71.8
1990	5.6	13.4	75.0
1995	6.0	12.9	77.4
2000	6.4	12.5	80.0

(1) Gross input fuel requirements, fossil fuel equivalent basis.

(2) Decreased by 15 percent over the forecast period to allow for energy conservation measures.

(3) Actual.

TABLE 22: FORECAST HOG FUEL USE, ONTARIO PULP AND PAPER INDUSTRY

Year	Hog Fuel Use	Fossil Fuel Equivalent Energy Value (1)
	10^3 O.D. Tons	10^{12} Btu
1977(2)	469	6.3
1980	700	9.5
1985	1,100	14.9
1990	1,500	20.3
1995	1,750	23.6
2000	2,000	27.0

(1) Assumes gross heating value of 18 million Btu/O.D.T. of hog fuel is converted to steam at an efficiency of 60 percent, versus 80 percent for the average fossil fuel boiler. Hence, the fossil fuel equivalent value of hog fuel is 18 million Btu/O.D.T. x $\frac{60}{80}$ *, or 13.5 million Btu/O.D.T.*

(2) Actual.

this bush residue, however, is not economically collectable and if ever utilized, may be as fibre input rather than as fuel. At current energy prices mill residue is competitive if supplies are available within a 75-radius of pulp and paper mills.* In the future, with further fuel price escalation, it is expected that the zone of economically available supplies of hog fuel will expand. By 1990, it is forecast that one million O.D. tons of currently unutilized wood residue will have displaced conventional fossil fuels for boiler-firing purposes; by 2000, the figure is forecast to increase to 1.5 million O.D. tons per annum, in addition to the 469,000 O.D. tons utilized during 1977.** Assumptions relating to forecast hog fuel use and its energy value are summarized in Table 22.

(iii) Potential Thermal Coal Demand

Based upon the foregoing projections, potential thermal coal demands are forecast in total in Table 23 and by level of discount in Table 24. While only about 6 x 10^{12} Btu of coal was burned in existing plants during 1974, about 26.5 x 10^{12} Btu was used in Ontario mills just seven years previously in 1967. It is estimated that sufficient equipment is still in place to burn at least 15 x 10^{12} Btu of coal annually. Based upon the levels of output forecast in Table 19, the 1980 production level could be achieved without the addition of new plant, so no coal use is shown for that discount category during 1980. After 1980, coal demand in existing plants is subtracted from total coal demand to leave a residual which is allocated between new and conversion demand on the basis of the proportion of total output constituted by incremental output after 1980. The potential thermal coal demand by the Ontario pulp and

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* *Abitibi Paper Company. This figure assumes that a 40-ton tractor trailer unit is used for transporting wood residues.*

** *Canadian Pulp and Paper Association.*

TABLE 23: POTENTIAL THERMAL COAL DEMAND, ONTARIO PULP AND PAPER INDUSTRY, 1980 to 2000

(10^{12} Btu)

Year	Total Fuel Requirement (1)	Lime Kiln Requirement (2)	Hog Fuel (3)	Residual Fuel Requirement (4)	Potential Coal Demand (5)
1980	67.2	4.8	11.2	51.2	46.1
1985	71.8	5.8	17.5	48.5	43.7
1990	75.0	7.0	23.9	44.1	39.7
1995	77.4	7.5	27.8	42.1	37.8
2000	80.0	8.0	31.8	40.2	36.2

(1) From Table 21.

(2) Forecast kraft output from Table 19 times 2.5 million Btu/ton.

(3) Energy values from Table 22 divided by 85 percent to allow for supplemental oil and natural gas boiler fuels.

(4) Column (1-2-3) = residual fuel requirement.

(5) Residual fuel requirement multiplied by 90 percent to calculate potential coal demand, allowing 10 percent for supplemental oil and natural gas boiler fuels.

TABLE 24: POTENTIAL THERMAL COAL DEMAND BY LEVEL OF DISCOUNT, ONTARIO PULP AND PAPER INDUSTRY, 1980 TO 2000

(10^{12} Btu)

Year	Total Potential Coal Demand	Required Coal Price Discount		
		$1.06/MMBtu	$0.61/MMBtu	$0.10/MMBtu
		(conversion)	(new plant)	(existing coal boilers)
1980	46.1	35.1	-	15
1985	43.7	25.7	3	15
1990	39.7	21.2	3.5	15
1995	37.8	18.2	4.6	15
2000	36.2	15.9	5.3	15

paper industry is shown to gradually decline over the forecast period since the relatively slow projected growth of the industry is more than offset by the forecast increase in hog fuel use.

1.5.2 Quebec

(a) Industry Structure and Markets

(i) Present Industry Structure and Historical Output

The Quebec pulp and paper industry is the largest of any province in Canada, with an pulp output of about 7 million tons in 1974, compared to 5.8 million in British Columbia, and 4.3 million in Ontario during the same year. In 1976 there were a total of 61 pulp and paper mills in Quebec, comprised of 9 pulp mills, 37 integrated pulp and paper mills, and 15 paper mills.* Newsprint is by far the most important single product, accounting for more than 70 percent of total paper and paperboard production in recent years. As shown in Table 25, pulp production in Quebec has grown rather slowly and sporadically since 1964, increasing at an average annual rate of about 1.3 percent from 1964 to 1976. After output peaked in 1974, it fell dramatically in 1975 as a result of the same industry-wide strike experienced in Ontario and weaker market conditions.

(ii) Future Output

The Quebec pulp and paper industry faces most of the same competitive disadvantages discussed in the Ontario pulp and paper section, including higher pulpwood, labour and transportation costs than its southern U.S. counterpart. On the positive side,

* *Canadian Pulp and Paper Association, 1977 Reference Tables, p. 6.*

TABLE 25: WOOD PULP PRODUCTION

Year	Output '000 tons		Year	Output '000 tons
1964	5,204		1971	6,245
1965	5,450		1972	6,496
1966	6,021		1973	6,163
1967	5,802		1974	7,002
1968	5,918		1975	5,730
1969	6,547		1976	6,390
1970	6,501			
	Growth rates:	1964-74	3.0% p.a.	
		1964-76	1.3% p.a.	

SOURCES: 1964-75: Statistics Canada, Catalogue 25-202 Annual, Canadian forestry statistics.

1976: Preliminary estimate of Canadian Pulp and Paper Association.

Quebec's abundant supply of hydro power may partially offset the foregoing disadvantages, particularly in the manufacture of newsprint. By converting existing groundwood-sulphite newsprint operations to TMP, the pollution problems associated with sulphite mills would be eliminated, lower-cost by-product chips could be used instead of roundwood input, and overall wood requirements per ton of newsprint reduced. These advantages would almost certainly outweigh the higher electricity consumption associated with the TMP process, given its relatively low cost in Quebec. Such a conversion, however, would require massive capital infusions which may not be forthcoming, in view of the low profitability of the industry in recent years.

The Quebec Department of Lands and Forests has formulated 3 alternate scenarios for total pulp production in the year 2000, ranging from 9 to 12 million tons per year. It is considered most probable that production will reach about 10 million tons per year by 2000, an average increase of about 1.4 percent per annum over the peak production level of 7 million tons experienced in 1974. This level of projected output has been adopted for the purposes of this forecast, with future growth occurring as shown in Table 26. It is estimated that kraft pulp mill will increase its share of total pulp output from about 23 percent in 1974 to 35 percent by the year 1990, as sulphite capacity is retired and replaced by kraft.

TABLE 26: FORECAST OUTPUT OF THE QUEBEC PULP AND PAPER INDUSTRY

(Million tons)

	Total Pulp	Kraft Pulp
1980	7.0	1.9
1985	7.7	2.4
1990	8.5	3.0
1995	9.2	3.2
2000	10	3.5

(b) Energy Use

(i) Past and Present

While the Quebec pulp and paper industry is the largest single industrial user of fossil fuel energy in the province, only about 8 percent was derived from coal during 1975, as shown in Table 27. Coal use has declined tremendously, from about 31.6 x 10^{12}Btu in 1964 to about 5 x 10^{12}Btu in 1975, as heavy fuel oil captured most of the markets formerly served by coal.

In addition to fossil fuels, about 374,000 oven-dried tons of hog fuel were burned in Quebec mills during 1975,*, equivalent to about 5.0 x 10^{12}Btu of fossil fuels.** Hence, total fuel use in 1975 was about 67.8 x 10^{12}Btu, or about 11.8 million Btu per ton of pulp produced, given the output of 5,730 tons of pulp during 1975.

TABLE 27: PULP AND PAPER FOSSIL FUEL ENERGY USE, QUEBEC, 1964-1975

	1964		1973		1974		1975	
Fuel Type	10^9Btu	%	10^9Btu	%	10^9Btu	%	10^9Btu	%
Coal	31,561	55	1,874	2.7	4,052	5.4	5,052	8.1
Natural Gas	741	1	550	0.8	1,298	1.7	940	1.5
Fuel Oil	25,235 (1)	44	66,351	96.5	70,167	92.9	56,715	90.4
Total	57,537		68,775		75,517		62,797	

SOURCE: Statistics Canada.

(1) Includes small quantities of diesel and kerosene.

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* *Canadian Pulp and Paper Association, personal communication.*

** *Assuming a gross heating value of 18 million Btu/O.D.T. and 60% boiler efficiency, versus 80% for fossil fuels.*

(ii) Future Energy Use

The 1975 energy use coefficient of 11.8 million Btu/ton combined with projections of future output and energy conservation possibilities outlined earlier, is used to forecast total fuel requirements in the Quebec pulp and paper industry as detailed in Table 28.

TABLE 28: FORECAST FUEL REQUIREMENTS, QUEBEC PULP AND PAPER INDUSTRY (1)

Year	Output (10^6 tons)	Fuel Per Unit of Output (2) (10^6 Btu/ton)	Total Fuel Requirement (10^{12} Btu)
1975 (3)	5.7	11.8	67.3
1980	7.9	11.4	79.8
1985	7.7	11.1	85.5
1990	8.5	10.7	91.0
1995	9.2	10.4	95.7
2000	10.0	10.0	100.0

(1) Gross input fuel requirements, fossil fuel equivalent basis.

(2) Decreased by 15% over the forecast period to allow for energy conservation savings.

(3) Actual.

It has been estimated that about 2.5 million O.D. tons of mill residue are produced in Quebec at current levels of harvest.* Since 89 percent of this residue is reportedly produced by pulp and paper mills, it seems reasonable to expect that virtually all of this residue is economically accessible. Therefore, it is forecast that use of hog fuel by pulp and paper mills will increase from about 418 thousand O.D.T. during 1977 to 2.5

* *Robert D. Neill, "Options for the use and disposal of bark", Pulp & Paper, Canada, March, 1976, p. 46.*

million O.D.T. by the end of the forecast period. Forecast hog fuel use and its associated energy value in fossil fuel equivalent terms are shown in Table 29.

TABLE 29: FORECAST HOG FUEL USE, QUEBEC PULP AND PAPER INDUSTRY

	Hog Fuel Use 10^3O.D. Tons	Fossil Fuel Equivalent Energy Value (1) 10^{12}Btu
1977 (2)	418	5.6
1980	750	10.1
1985	1,500	20.3
1990	2,000	27.0
1995	2,250	30.4
2000	2,500	33.8

(1) 13.5 million Btu/O.D.T. See Ontario section for derivation.

(2) Actual.

(iii) Potential Thermal Coal Demand

Potential thermal coal demands are forecast in total in Table 30 by deducting non-substitutable oil and natural gas requirements and hog fuel energy from the total fuel requirement forecast in Table 28. As noted in Table 27, coal use during 1975 was only about 5 x 10^{12}Btu, but in view of the fact that coal was almost 32 x 10^{12}Btu a decade earlier, it is estimated that enough equipment is still in place to burn at least 15 x 10^{12}Btu of coal per annum. The distribution of coal demand between the new and conversion markets is allocated in Table 31 on the basis of the proportion of total output constituted by incremental output after 198C.

TABLE 30: POTENTIAL THERMAL COAL DEMAND, QUEBEC PULP AND PAPER INDUSTRY, 1980 TO 2000

(10^{12}Btu)

	Total Fuel Requirement (1)	Lime Kiln Requirement (2)	Hog Fuel (3)	Residual Fuel Requirement (4)	Potential Coal Demand (5)
1980	79.8	4.8	11.9	63.1	56.8
1985	85.5	6.0	23.9	55.6	50.0
1990	91.0	7.5	31.8	51.7	46.5
1995	95.7	8.0	35.8	51.9	46.7
2000	100.0	8.8	39.8	51.4	36.3

(1) From Table 28.

(2) Forecast kraft output from Table 26 times 2.5 million Btu/ton.

(3) Energy values from Table 29 divided by 85% to allow for supplemental oil and natural gas boiler fuels.

(4) Column (1-2-3) = residual fuel requirement.

(5) Residual fuel requirement multiplied by 90% to calculate potential coal demand, allowing 10% for supplemental oil and gas boiler fuels.

TABLE 31: POTENTIAL THERMAL COAL DEMAND BY LEVEL OF DISCOUNT, QUEBEC PULP AND PAPER INDUSTRY

(10^{12}Btu)

	Total Potential Coal Demand	Required Coal Price Discount		
		$1.06/MM Btu (Conversion)	$0.61/MM Btu (New Plant)	$0.10/MM Btu (Existing Coal-Fired Boilers)
1980	56.8	41.8	-	15.0
1985	50.0	31.8	3.2	15.0
1990	46.5	25.9	5.6	15.0
1995	46.7	24.1	7.6	15.0
2000	46.3	21.9	9.4	15.0

1.5.3 Atlantic Provinces

(a) Industry Structure and Output

(i) Present Industry Structure and Output

Since output data are not available for the individual Atlantic Provinces, they must be considered in aggregate. New Brunswick is the leading pulp and paper producer in the Atlantic region, with 11 of the 19 mills, followed by Nova Scotia with 5, and Newfoundland with 3. During 1974 pulp production of all grades reached about 3.6 million tons of which about 30 percent was kraft pulp.* While no historical production figures are available in published form, it may be deduced that 1974 was also the peak output year to date in the Atlantic region, with output sharply reduced in 1975 and 1976 due to a combination of strikes and poor market conditions. Hence, 1974 is used as the base year since it is the most current representative year for which production data were available.

(ii) Future Output

In other regions of Canada, pulp and paper expansion in the future may be limited as a result of economically accessible timber supplies, but in the Atlantic provinces it currently appears as if future output will be constrained by a physical lack of adequate timber reserves. A recent study has concluded that in both Nova Scotia and New Brunswick, the average softwood harvest of recent years has exceeded the sustainable yield at the existing level of forest management.** Severe spruce budworm infestations of recent years have destroyed over 20 percent of the annually allowable cut in New Brunswick in recent years and could reduce pulp and paper output if unchecked.* While Newfoundland, as a whole, possesses a physical reserve of softwood, much of the supply is located in Labrador and is not considered to be economically accessible. In fact, a kraft-based linerboard mill at Stepheville was closed more than a year ago due to insufficient wood supply. According to a recent report, Abitibi Paper Co. will replace the 350 M tpy facility with a 150 M tpy newsprint mill.** This reduction is size, combined with the higher yield of mechanical pulp used for newsprint fibre, should reduce wood requirements to about one-quarter of their former level.

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* *Statistics Canada, unpublished data, personal communication, January 1979.*

** *F.L.C. Reed, op.cit., pp. 19-27.*

Based upon the foregoing considerations with respect to wood supply, it is concluded that pulp and paper output in the Atlantic provinces is unlikely to increase beyond the 1974 level of production during the forecast period. Taking into account the change in capacity at Stephenville, it is forecast that output will be about 3.4 million tpy throughout the forecast period, with kraft reduced to about 750 thousand tpy. Given the tight wood supply situation, kraft production is not expected to increase as a proportion of total output over the forecast period.

(b) Energy Use

(i) Past and Present Energy Use

Fossil fuel energy use in paper and allied industries in the Atlantic provinces from 1964 to 1974 is shown in Table 32.

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* *Ibid.*

** *Financial Post, December 2, 1978, p. 4.*

While coal was once a major fuel, accounting for about 11 x 10^{12} Btu, or 36 percent of total fossil fuel requirements in 1964, its use had virtually ceased in 1971 as it was displaced by heavy fuel oil.

TABLE 32: PULP AND PAPER FOSSIL FUEL ENERGY USE, ATLANTIC PROVINCES, 1964-1974

Fuel Type	1964		1969		1974	
	10^{12}Btu	%	10^{12}Btu	%	10^{12}Btu	%
Coal (1)	11.0	36	5.7	17	-	-
Fuel Oil (2)	19.5	64	27.2	83	51.3	100
Total	30.5	100	32.9	100	51.3	100

SOURCE: Statistics Canada, Catalogue 57-506, occasional, Consumption of purchased fuel and electricity, 1962-1974.

(1) 25.5 million Btu/ton.

(2) Includes minor quantities of kerosene and diesel oil as well as light and heavy fuel oils.

It is estimted that hog fuel use in this region during 1974 was in the vicinity of 300 thousand O.D.T., equivalent to about 4.1 x 10^{12}Btu.* Total fuel use in 1974 was therefore about 55.4 x 10^{12}Btu or 15.4 x 10^{6}Btu/ton of pulp produced, given the output of 3.6 million tons during that year.

(ii) Future Energy Use

Using the above energy use coefficient and previous projections of output and energy conservation savings, total fuel requirements for this region are forecast in Table 33.

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* *1974 data not available, but CPPA figures indicate that hog fuel use in this region reached 350 thousand O.D.T. during 1977.*

TABLE 33: FORECAST FUEL REQUIREMENTS, ATLANTIC PULP AND PAPER INDUSTRY(1)

Year	Output (10^6 tons)	Fuel Per Unit of Output(2) (10^6Btu/ton)	Total Fuel Requirement (10^{12}Btu)
1974(3)	3.6	15.4	55.4
1980	3.4	14.9	50.7
1985	3.4	14.4	49.0
1990	3.4	14.0	47.6
1995	3.4	14.0	45.9
2000	3.4	13.1	44.5

(1) Gross input fuel requirements, fossil fuel equivalent basis.

(2) Decreased by 15% over the forecast period to allow for energy conservation savings.

(3) Actual.

Total bark production at mills in the Atlantic region has been placed at about 1.15 million O.D.T. at current levels of harvest, while bark production at pulp and paper mills is estimated to be about 867 thousand O.D.T. annually.* Since not all lumber mill wastes will be available to pulp mills, the latter figure is probably more appropriate. Taking into consideration the probable reduction in annual harvest in the region, it is projected that hog fuel use will increase to about 750 thousand O.D.T. by the end of the forecast period as shown in Table 34.

(iii) Potential Thermal Coal Demand

Potential thermal coal demands are forecast in Tables 35 and 36 as described in previous regional analyses.

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* *Neill, op.cit., p. 46.*

TABLE 34: FORECAST HOG FUEL USE, ATLANTIC PULP AND PAPER INDUSTRY

	Hog Fuel Use 10^3 ODT	Fossil Fuel Equivalent Energy Value(1) 10^{12} Btu
1977(2)	350	4.7
1980	450	6.1
1985	550	7.4
1990	650	8.8
1995	700	9.5
2000	750	10.1

(1) 13.5 million Btu/ODT.

(2) Actual.

TABLE 35: POTENTIAL THERMAL COAL DEMAND, ATLANTIC PULP AND PAPER INDUSTRY, 1980-2000

(10^{12}Btu)

	Total Fuel Requirement (1)	Lime Kiln Requirement (2)	Hog Fuel (3)	Residual Fuel Requirement (4)	Potential Coal Demand (5)
1980	50.7	1.9	7.2	41.6	37.4
1985	49.0	1.9	8.7	38.4	34.6
1990	47.6	1.9	10.4	35.3	31.8
1995	45.9	1.9	11.2	32.8	29.5
2000	44.5	1.9	11.9	30.7	27.6

(1) From Table 33.

(2) Forecast kraft output times 2.5 million Btu/ton.

(3) Energy values from Table 34 divided by 85 percent to allow for supplemental oil and natural gas boiler fuels.

(4) Column (1-2-3) = residual fuel requirement.

(5) Residual fuel requirement multiplied by 90% to calculate potential coal demand, allowing 10% for supplemental oil and gas boiler fuels.

TABLE 36: POTENTIAL THERMAL COAL DEMAND BY LEVEL OF DISCOUNT, ATLANTIC PULP AND PAPER INDUSTRY, 1980-2000

(10^{12}Btu)

	Total Potential Coal Demand	Required Coal Price Discount		
		$1.06/MM Btu (Conversion)	$0.61/MM Btu (New Plant)	$0.10/MM Btu (Existing Coal-Fired Boilers)
1980	37.4	32.4	-	5
1985	34.6	29.6	-	5
1990	31.8	26.8	-	5
1995	29.5	24.5	-	5
2000	27.6	22.6	-	5

1.5.4 Prairie Provinces

(a) Present and Future Output

The Prairie Provinces are currently the smallest regional producers of pulp and paper products in Canada. There are only two major mills in both Alberta and Manitoba, and one in Saskatchewan. During 1974 pulp output reached 967 thousand tons of which about 74 percent was kraft.

While output is currently relatively small in this region, however, economically-accesible timber reserves are capable of supporting a larger growth rate in pulp and paper output than elsewhere in the country. The economically accessible softwood timber reserve is estimated to be about 7 million cubic metres compared to an average harvest of 10.7 million cubic metres in recent years.* If this reserve were to be fully utilized over the forecast period and pulp and paper output were to increase at the same rate as the softwood harvest, production would increase by 2 percent per annum from 1975 to 2000. For a number of reasons, however, output could grow considerably faster than this. First, the preceding calculation does not take into account the potential utilization of large economically-accessible hardwood reserves in this region, estimated to exceed 13 million cubic metres. Second, it is expected that future capacity expansions will be more heavily weighted in favour of mechanical pulping techniques, which yield almost twice the output per unit of wood input when compared to the chemical kraft process that is presently dominant in this region. Taking these factors into account, it seems reasonable to project an output increase of about 2.8 percent per annum from 1980 to

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* *F.L.C. Reed, op.cit., pp. 22-23.*

2000, starting grom a production level of one million tons per annum in 1980. Kraft pulp production is forecast to decrease from 75 percent in 1980 to 60 percent by the end of the forecast period. This forecast is detailed in Table 37.

TABLE 37: FORECAST OUTPUT OF THE PULP AND PAPER INDUSTRY, PRAIRIE PROVINCES

(Million tons)

	Total Pulp	Kraft Pulp
1980	1.0	.8
1985	1.1	.8
1990	1.3	.9
1995	1.5	1.0
2000	1.7	1.0

(b) Energy Use

(i) Past and Present

Unlike other regions, coal use in Prairie pulp and paper mills increased marginally from 1964 to 1974. The volumes shown in Table 38 consist of Bienfait, Saskatchewan lignite, which is burned in the Pine Falls, Manitoba newsprint mill of Abitibi Paper Co. Hog fuel use during 1974 is estimated to have been about 180 ODT, equivalent to about 2.4 x 10^{12}Btu of fossil fuels. Total 1974 fuel use amounts to about 14.4 x 10^{12}Btu, when hog fuel energy use is added to the fossil fuel use shown in Table 38. Given the 1974 pulp output of 967 thousand tons of pulp, unit fuel consumption is in the vicinity of 14.9 x 10^{12}Btu per ton.

TABLE 38: PULP AND PAPER FOSSIL FUEL ENERGY USE, PRAIRIE REGION, 1964-1974

	1964		1974	
Fuel type	10^{12}Btu	%	10^{12}Btu	%
Coal	1.5	25	1.8	15
Fuel Oil	0.2(1)	3	2.2	18
Natural Gas	4.3	72	8.0	67
Total	6.0	100	12.0	100

SOURCE: Statistics Canada, Catalogue 57-506, Consumption of purchased fuel and electricity, 1962-1974.

(1) Includes small amounts of kerosene and stove oil in addition to light and heavy fuel oils.

(ii) Future Energy Use

Future fuel requirements are forecast in Table 39 based upon the output and energy use projections detailed earlier.

It has been estimated that about 450 thousand ODT of bark is produced in Prairie region pulp and paper mill, along with another 200 thousand ODT is sawmills, for a total of 650 thousand ODT.* While much of the sawmill waste may not be within reach of pulp mills, particularly in Alberta, pulp mill bark production will increase considerably if pulp output is expanded as forecast herein. On this basis it is estimated that hog fuel usage in pulp mills will increase to 650 thousand ODT by the end of the forecast period as shown in Table 40.

(iii) Potential Thermal Coal Demand

Potential thermal coal demands are forecast in Tables 41 and 42 as described in the Ontario system.

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* *Neill, op.cit., p. 46.*

TABLE 39: FORECAST PULP AND PAPER INDUSTRY FUEL REQUIREMENTS, PRAIRIE PROVINCES(1)

Year	Output (10^6 tons)	Fuel Per Unit of Output (10^6Btu/ton)	Total Fuel Requirement (10^{12}Btu)
1974(3)	0.967	14.9	14.4
1980	1.0	14.4	14.4
1985	1.1	14.0	15.4
1990	1.3	13.5	17.6
1995	1.5	13.1	19.7
2000	1.8	12.7	21.6

(1) Gross input fuel requirements, fossil fuel equivalent basis.

(2) Decreased by 15% over the forecast period to allow for energy conservation savings.

(3) Actual.

TABLE 40: FORECAST PULP AND PAPER INDUSTRY HOG FUEL USE, PRAIRIE PROVINCES

	Hog Fuel Use 10^3ODT	Fossil Fuel Equivalent Energy Value(1) 10^{12}Btu
1977(2)	187	2.5
1980	250	3.4
1985	400	5.4
1990	550	7.4
1995	600	8.1
2000	650	8.8

(1) 13.5 million Btu/ODT.

(2) Actual.

TABLE 41: POTENTIAL THERMAL COAL DEMAND, PULP AND PAPER INDUSTRY, PRAIRIE PROVINCES, 1980-2000

(10^{12} Btu)

	Total Fuel Requirement (1)	Lime Kiln Requirement (2)	Hog Fuel (3)	Residual Fuel Requirement (4)	Potential Coal Demand (5)
1980	14.4	2.0	4.0	8.4	7.6
1985	15.4	2.0	6.4	7.0	6.3
1990	17.6	2.3	8.7	6.6	5.9
1995	19.7	2.5	9.5	7.7	6.9
2000	21.6	2.5	10.4	8.7	7.8

(1) *From Table 39.*

(2) *Forecast kraft output times 2.5 million Btu/ton.*

(3) *Energy values for Table 40 divided by 85 percent to allow for supplemental oil and natural gas boiler fuels.*

(4) *Column (1-2-3) = residual fuel requirement.*

(5) *Residual fuel requirement multiplied by 90% to calculate potential coal demand allowing 10% for supplemental oil and gas fuels.*

TABLE 42: POTENTIAL THERMAL COAL DEMAND BY LEVEL OF DISCOUNT, PULP AND PAPER INDUSTRY, PRAIRIE PROVINCES, 1980-2000

(10^{12} Btu)

	Total Potential Coal Demand	Required Coal Price Discount $1.06/MM Btu (Conversion)	$0.61/MM Btu (New Plant)	$0.10/MM Btu (Existing Coal-Fired Boilers)
1980	7.6	5.8	-	1.8
1985	6.3	4.1	0.4	1.8
1990	5.9	3.2	0.9	1.8
1995	6.9	3.4	1.7	1.8
2000	7.8	3.5	2.5	1.8

1.5.5 British Columbia

While the installed capacity of the pulp and paper industry of B.C. is second only to that of Quebec, less than 20 percent of the annual cut is used for pulp production. The remaining 80 percent is consumed by sawmills, plywood mills, and shingle mills, which, in turn, generate wood wastes far in excess of the quantity required to supply their own energy needs. As a result of the historical pattern of development, most pulp mill capacity is within economic reach of enough hog fuel from wood industries to supply the majority of its power boiler fuel requirements.

A recent study has forecast that in the year 2000 there will continue to be a surplus of hog fuel in all regions of the province except the south coast where the major concentration of pulp and paper capacity is located.* As the price of fossil fuels increases, however, it may be possible to augment the present south coastal supply by utilizing bush residue, waste from dry-land sorting yard, and non-commercial species. In fact, studies are currently underway to explore the viability of all these possibilities. Even if these prospects of increasing hog fuel supply are not realized, however, south coastal mills will shortly, if not already, have the capacity to provide the majority of their power boiler fuel requirements from hog fuel.* In view of the large capital expenditures recently committed to specialized hog burning equipment, it is unlikely that south coastal mills even consider installing coal-burning equipment to supply the remainder of their power boiler fuel requirements.** Therefore, given the prospects for energy self-sufficiency in the B.C. pulp and paper industry, no coal use is foreseen in this regional market.

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* *Reid, Collins and Associates Ltd., Hog Fuel Availability in British Columbia, British Columbia Wood-Waste Energy Coordinating Committee, May 1978. This conclusion is based upon the assumption that no additional pulpmill capacity will come into production over the forecast period. While this assumption may not prove to be strictly correct, there is general agreement that with the current harvest approaching the sustainable limit in economically accessible areas, the scope for future expansion of mill capacity is quite limited.*

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* *A recent survey by Canadian Resourcecon Limited of the present and projected energy mix of Vancouver Island pulp and paper mills indicated that about two-thirds of the power boiler fuel requirements of these mills are expected to be derived from hog fuel by the early 1980's.*

** *None of the mills contacted anticipated the use of coal in the foreseeable future.*

2.0 CEMENT

2.1 Process Description

In order to produce cement, an accurately proportioned mixture of finely ground materials containing calcium, silica, alumina and iron oxide is sintered in a kiln at high temperatures to produce a fused material called clinker. The clinker is then cooled, blended with gypsum and ground to a fine powder to form cement as the finished product.

Two main processes, the wet and dry, are currently employed in the production of cement. In the wet process the raw materials are ground and mixed with water and fed into the kiln in the form of a slurry containing about 35 percent water.* In the dry process, on the other hand, the raw materials are mixed, ground, and fed into the kiln in their dry state (less than 0.5 percent water).** The two processes are essentially similar in other stages of manufacture.

Cement manufacture requires two main types of end-use energy: mechanical energy, primarily for grinding raw materials and cement clinker; and process heat for kiln firing. Electricity provides virtually all of the mechanical energy requirements and is not readily substitutable by other energy forms.

The process heat for kiln firing, which accounts for almost all of the fossil fuel used in cement plants, may be supplied from a variety of sources. In addition to conventional fossil fuels such as natural gas, heavy fuel oil, and coal, other fuels such as petroleum coke and garbage have also been used to fire cement kilns. Fuel requirements per ton of product vary widely depending on the nature of the process and vintage of plant. A new dry-process plant equipped with a 4-stage preheater and precalciner may require as little as 2.8 million Btu/ton, while older wet plants may require in excess of 6 million Btu/ton. Wet process plants are, however, inherently less efficient since more heat is required to evaporate the much higher moisture content of the kiln feed - even the most efficient wet plants require in excess of 4 million Btu/ton.

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* *L.P. MacDonald and F.J. Hopton, Experimental Burning of Delayed Coke in a Wet Process Cement Kiln, Environmental Protection Service, Fisheries and Environment Canada, Report No. EPS 4-WP-77-5, 1977.*

** *Ibid.*

2.2 Industry Structure and Output

(a) Present Industry Structure and Output

Over the past 15 years, 1962 to 1977, Canadian cement production has increased at an average rate of about 3.3 percent per annum. During the last three years, however, cement production has fallen below peak output levels reached in 1974 as shown below.

TABLE 43: CANADIAN CEMENT PRODUCTION - 1962-1977(1)

Year	M Tons	Year	M Tons
1962	6,879	1970	7,946
1963	7,014	1971	9,076
1964	7,847	1972	10,039
1965	8,931	1973	11,126
1966	8,931	1974	11,436
1967	7,995	1975	10,985
1968	8,166	1976	10,609
1969	8,250	1977	11,132(P)
Average annual growth rates:		1962-1977	3.3%
		1962-1974	4.3%
(P) = Preliminary		1974-1977	-0.9%

SOURCE: EMR Canada, Canadian Minerals Yearbook, 1962-1977.

(1) Producers shipments plus quantities used by producers.

Cement capacity in Canada is heavily concentrated in the more populous provinces of Ontario and Quebec since the low value/ weight ratio of cement makes it necessary for producers to locate close to markets. Cement production by province during 1977 is shown in Table 44, while productive capacity at the end of 1977 as compiled by D.H. Stonehouse is summarized in Table 45.

TABLE 44: CEMENT PRODUCTION BY PROVINCE, 1977(1)

	'000 tons
British Columbia	1,041
Alberta	1,160
Saskatchewan	371
Manitoba	647
Ontario	4,041
Quebec	3,328
New Brunswick	243(2)
Nova Scotia	194(2)
Newfoundland	107(2)
	11,132

(1) From Canadian Minerals Yearbook, 1977 cement preprint, except as noted.

(2) Estimated on the basis of share of value of production in Atlantic provinces times residual tonnage.

(b) Future Output

Long-term national cement production forecasts generally fall within the range of two to three percent per annum to the year 2000. Energy, Mines and Resources Canada has forecast an annual growth rate of about 1.9 percent for Canadian cement production over the period 1973-2000.* Over the same time

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* *EMR Canada, Present and Projected Energy Consumption in the Mineral Industry of Canada, Mineral Bulletin MR 164, 1976, p. 15.*

TABLE 45: CANADIAN CEMENT PLANTS

Company	Plant Location	Process	Major Fuels	Capacity
Atlantic Region				(000 Tons/Yr)
North Star Cement	Cornerbrook, Nfld.	Dry	oil	175
Canada Cement Lafarge	Brookfield, N.S.	Dry	oil, coal	522
Canada Cement Lafarge	Havelock, N.B.	Dry	oil, coal	360
Total Atlantic Region				1,057
Quebec				
Canada Cement Lafarge	St. Constant	Dry	oil, gas, coal	1,050
Ciment Quebec Inc.	St. Basile	Wet	oil	380
Independent Cement	Joliette	Dry	oil	1,200
Miron Company Ltd.	St. Michel	Dry	oil	1,050
St. Lawrence Cement	Villaneuve	Wet	oil, coal	787
Total Quebec Region				4,467
Ontario				
Canada Cement Lafarge	Woodstock	Wet	gas, coal	595
Canada Cement Lafarge	Bath	Dry	oil, gas	1,100
Lake Ontario Cement	Picton	Dry	gas, coal	1,670
St. Lawrence Cement	Clarkson	Wet/Dry	oil, coal	1,750
St Mary's Cement	Bowmanville	Wet	coal	750
St. Mary's Cement	St. Mary's	Dry	gas	1,030
Total Ontario Region				6,895
Manitoba				
Canada Cement Lafarge	Winnipeg	Wet	oil, gas	630
Inland Cement Industries	Winnipeg	Wet	oil, gas	325
Saskatchewan				
Inland Cement Industries	Regina	Dry	gas	225
Alberta				
Canada Cement Lafarge	Exshaw (1)	Dry	gas	800
Inland Cement Industries	Edmonton (2)	Wet	gas	628
Total Prairie Region				2,608

Cont'd.

TABLE 46: CANADIAN CEMENT PLANTS (Cont'd.)

Company	Plant Location	Process	Major Fuels	Capacity
				(000 Tons/Yr)
British Columbia				
Canada Cement Lafarge	Lulu Island	Wet	oil, gas	615
Canada Cement Lafarge	Kamloops	Dry	gas	210
Ocean Cement Ltd.	Bamberton(3)	Wet	oil	550
Ocean Cement Ltd.	Tilbury Island	Dry	oil, gas	1,100
Total B.C. Region				2,475
TOTAL CANADIAN CAPACITY				17,502

SOURCE: D.H. Stonehouse, "Cement", Canadian Minerals Yearbook, 1976 preprint, Mineral Development Sector, EMR Canada.

(1) Expansion program planned.

(2) Expansion program underway.

(3) Due to be phased out as Tilbury Island plant reaches full output, probably by 1980.

horizon, forecasts of 3.2 percent and 2.6 percent per annum growth rates have been made for U.S. cement production and output in the rest of the world, respectively.* For the purposes of this study it is forecast that cement production to the year 2000 will increase at a rate of 1.9 percent per annum in all provinces except Alberta and Nova Scotia.

In Alberta, the Energy Resources Conservation Board assumes in its current energy forecast** that cement demand will increase from the current level of 1.4 million tons by 100 thousand tons per year until 2006. This assumption has been adopted herein. Cement production in Nova Scotia also seems likely to increase at a faster rate than the national average with the doubling of Canada Cement Lafarge's capacity at Brookfield being completed during 1977. It is forecast that cement production in Nova Scotia will increase from about 200,000 tons in 1977 to the Brookfield plant's ultimate capacity of about 520,000 tons per annum by the year 2000. Forecast output of the cement industry is shown in Table 47.

TABLE 47: FORECAST OUTPUT OF THE CEMENT INDUSTRY ('000 tons)

Province	1980	1985	1990	1995	2000
British Columbia	1,101	1,210	1,330	1,461	1,605
Alberta	1,160	2,200	2,700	3,200	3,700
Saskatchewan	393	431	474	521	572
Manitoba	685	752	826	908	997
Ontario	4,276	4,698	5,161	5,671	6,230
Quebec	3,521	3,869	4,251	4,670	5,130
New Brunswick	257	282	310	341	375
Nova Scotia	221	274	339	421	522
Newfoundland	113	124	137	150	165
Total	11,727	13,840	15,437	17,343	19,073

(1) From Table 45.

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* *Brinton C. Brown, "Cement" Mineral Facts and Problems 1975, U.S. Bureau of Mines, p. 17.*

** *Energy Resources Conservation Board, Energy Requirements in Alberta, 1977-2006, Calgary, Alberta, September 1978.*

2.3 Energy Use

(a) Past and Present

In the past, coal was the dominant kiln fuel in cement manufacture, both in Canada and throughout the world. While coal use in the Canadian industry peaked at about 1.15 million tons in 1957, it continued as a major fuel until comparatively recently with almost a million tons being used to provide half the process heat in 1966. The rise of coal prices relative to those of oil and gas during the 1960's, however, resulted in coal use decreasing to only a small fraction of total energy requirements by 1975 as shown in Table 48.

TABLE 48: FOSSIL FUEL ENERGY USE IN THE CANADIAN CEMENT INDUSTRY, 1966-1976

	1966		1975		1976	
	10^9 Btu	%	10^9 Btu	%	10^9 Btu	%
coal(1)	24,177	49	5,334	10	9,177	17
natural gas	15,386	31	25,246	45	25,040	46
fuel oil	9,687	20	25,183	45	19,942	37
TOTAL	49,250	100	55,763	100	54,159	100

SOURCE: Statistics Canada Catalogue 44-204, Cement Manufacturers.

(1) Bituminous coal converted to gross heat value using a factor of 25.5 MM Btu/ton, lignite at 15 MM Btu/ton.

It is interesting to note that during 1976, the year for which most recent energy use data are available, coal consumption rebounded strongly from the previous year. The trend towards increased use of coal over this time period can be explained by the fact that cement manufacture, as a very energy intensive process was particularly vulnerable to the large increases in oil and natural gas prices which occurred during the same period. The cost of purchased fuel and electricity increased from about 23 percent of value added in the Canadian cement industry in 1973 to almost 34.8 percent in 1975, an increase of more than 50 percent in just two years. Given the price scenario assumed in this forecast in which oil and gas prices continue to increase in real terms, the cement industry will have a powerful incentive to minimize energy costs, especially through the substitution of cheaper fuels, such as coal, for oil and gas. Improvements in process efficiency, and the replacement of normal portland cement by less energy-intensive materials such as fly ash and blast furnace slag will also undoubtedly be pursued by Canadian cement manufacturers as means of offsetting rising energy costs.

(b) Future Energy Use

i) Interfuel substitution

Although a number of alternate fuels may be used, the cement industry is most likely to turn to coal as an alternate fuel since it is not only relatively cheap and abundant, but also a proven and familiar fuel in the cement industry. Coal ash does not present a disposal problem since it may be incorporated into the clinker without adverse effects on cement quality by adjusting the chemical composition of the raw materials entering the cement kiln.* Coal with sulphur levels in the range of 3 to 3.5 percent is currently being burned without major problems in an existing wet process kiln in Ontario. However, newer kilns equipped with suspension preheaters or flash calciners are more vulnerable to sulphate build-ups which may plug up equipment and adversely affect the setting properties of the finished cement. Therefore, a lower-sulphate coal may be required in such kilns, particularly if the sulphur content of the limestone feed is high.

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* *Skovronek, op.cit., p. 62.*

In the U.S., where cement manufacturers are faced with both price increases and availability problems for oil and natural gas, many plants have installed coal burning equipment and have acquired coal mines to guarantee their energy supply. By 1976 coal and coke accounted for 55 percent of fossil fuel use in American cement plants, compared with 38 percent in 1972. Over the same period the consumption of natural gas declined by 41 percent and fuel be 38 percent.* It is expected that 90 percent of the U.S. cement industry will have coal-burning capability by 1980.**

To convert a cement plant to coal use from oil or natural gas requires that additional facilities and equipment be installed for coal unloading, storage, secondary reclaiming, primary crushing, storage in bunkers, milling, feed to the kilns (including related conveyor systems), and instrumentation and controls.*** The conversion costs associated with such facilities are highly site-specific, estimated to range from about $3.00 to $6.00 (1978 dollars) per annual ton of cement production capacity.**** Operating costs associated with coal handling and preparation are estimated to involve a premium of about 10¢/MM Btu over the cost of operating an oil- or gas-fired kiln, according to an industry source. Table 49 presents an estimate of the price differential range required to convert from oil or gas to coal.

* *Rock Products, July 1977, p. 17.*

** *Pit and Quarry, June 1978, p. 53.*

*** *Pit and Quarry, June 1975, p. 58.*

**** *Based upon the capital cost of recent plant conversions in the U.S. as reported in recent issues of Pit and Quarry and the U.S. Minerals Yearbook and related to plant capacities. Capital cost figures inflated at 10% per annum to convert to 1978 dollars.*

TABLE 49: CEMENT PLANT COAL CONVERSION COSTS

Assumptions:

Plant size : 1 million tons per year(1)
Fossil fuel use: 4.66 MM Btu/ton(2)

		Case 1	Case 2
1.	Capital cost of coal conversion(3)	$3.00/ton	$6.00/ton
	Total conversion cost	$3 million	$6 million
	Annual capital cost @ 20%	$600,000	$1,200,000
	Annual fossil fuel use	4.66×10^{12} Btu	4.66×10^{12} Btu
	Conversion capital cost/MM Btu	$0.13	$0.26
	Incremental operating cost/MM Btu(4)	$0.10	$0.10
	Total conversion cost/MM Btu	$0.23	$0.36

(1) *Considered to be a representative plant size.*

(2) *Based upon 1976 average energy intensity for Canadian-produced cement and clinker.*

(3) *Representative range of conversion costs - see references below.*

(4) *Industry source.*

At present, 8 out of the 23 cement plants in Canada already process at least partial coal-burning capability as noted in Table 45.

It is expected that coal will be able to provide 90 percent of kiln fuel requirements in the Canadian cement industry, with the remaining 10 percent allocated to oil and natural gas as standby and supplemental fuels.

ii) Process efficiency

During 1976 the Canadian cement industry used a total of $54{,}159 \times 10^9$ Btu of kiln fuels to produce 11.62 million tons of cement and clinker combined,* an energy requirement in the order of 4.66 million Btu/ton of product. In comparison, the U.S. cement industry required an average of 5.6 million Btu/ton over the same year. However, as noted earlier, state-of-the-art dry process plants may use as little as 2.8 million Btu/ton. Hence the Canadian cement industry has room for considerable improvement in process efficiency even though it is ahead of its American counterpart.

With the cost of new plant construction now in the range of $100 to $125 per ton of annual capacity,** and the cost of converting from the wet to the dry process at about $60 to $70 per ton,*** it is not realistic to expect that the Canadian cement industry will convert en masse to the most efficient kilns in the near future, particularly when the rate of capacity utilization was only 72 percent during 1977.**** Instead, improvements in process efficiency will occur more gradually over the forecast period.

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* *Stonehouse, op.cit.*

** *Rock Products, December 1977, p. 44.*

*** *Industry source.*

**** *Stonehouse, op.cit.*

iii) Materials substitution

A second, less capital intensive measure for reducing energy costs in the cement industry, is to mix portland cement with blast furnace slag or fly ash to produce a blended cement. Since these materials are by-products of burning, the energy-intensive kiln operation is eliminated. While blended cements are not commonly used in North America, they have been widely accepted in Europe for many years. In France, for example, blended cements accounted for 57 percent of total cement production in 1972; in the U.S. such cements currently constitute less than 2 percent of total output.* The relative proportions of fly ash, blast furnace slag, and portland cement that can be used to produce a blended cement are governed largely by the nature of its use. It has been reported that U.S. strength requirements for Type I portland cement (general use) can be met by the following blends:**

	Portland cement	Slag	Fly ash
1)	80%	-	20%
2)	70%	30%	-
3)	50%	30%	20%

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* *R.H. Brink, "Cementitious properties of low-energy materials"; Proceedings of a Seminar, Energy and Resource Conservation in the Cement and Concrete Industry, CANMET, EMR, Ottawa, Nov. 8-9, 1976; Paper 3.1.*

** *Brink, op.cit.*

While there is some early strength reduction (up to 28 days) in concrete made from these blends as compared to concrete made from straight portland cement, these blends provide superior strength when fully cured. Thus, kiln fuel use may be reduced as much as 50 percent by using such blends to produce concrete where high early strength is not required.

With the anticipated increase in coal-fired thermal-electric generation detailed elsewhere in this report, the production of fly ash (in most parts of Canada) will be greatly increased over the forecast period. This ash, which currently presents a disposal problem, represents a potentially valuable and abundant resource for the manufacture of blended cements. While the availability of blast furnace slag is more localized than that of fly ash, with most blast furnace capacity located in Ontario, a large proportion of Canadian cement capacity is located around Lake Ontario, in close proximity to the steel industry. In 1976 two slag-cement companies were operating in Ontario, with one already planning to expand after operating for less than a year.*

Given the availability of both blast furnace slag and fly ash in large quantities in close proximity to most cement producers, in the face of rising costs it seems likely that blended cements will account for a larger proportion of Canadian cement production by the turn of the century. It is forecast that the use of more efficient cement kilns in combination with the trend toward blended cements will gradually reduce kiln consumption from about 4.66 MM Btu per ton of cement in 1976 to 3 MM Btu/ton by the year 2000. This represents a decrease in unit fuel consumption of about 1.8 percent per annum. In comparison a voluntary commitment has been made by the Canadian cement industry to reduce energy use per unit of output by 9 to 12 percent from 1974 to 1980, or by about 1.6 to 2.1 percent per annum.

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* *P. Mollard, "Canadian Experience with the Use of Blended Cements", Proceedings of a Seminar, Energy and Resource Conservation in the Cement Industry, CANMET, EMR, Ottawa, Nov. 8-9, 1976; Paper 3.5.*

(c) Potential Thermal Coal Demand

Potential thermal coal consumption in the Canadian cement industry is forecast in Table 8, based upon the following assumptions detailed earlier in this section:*

(i) Cement output will increase at a rate of 1.9 percent per annum, except as noted;

(ii) Coal will provide 90 percent of process heat requirements;

(iii) Cement kiln fossil fuel requirements will be gradually reduced from 4.66 MM Btu/ton in 1976 to 3 MM Btu/ton by the end of the forecast period.

While Table 51 indicates that there is enormous potential for increased coal use in the cement industry compared to the 1976 level of usage (9.177×10^9 Btu), little increase is forecast beyond 1990. This is because the relatively slow growth in forecast output is almost exactly offset by the forecast continuing decrease in energy requirements per unit of output.

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* *This method of calculation applies to all provinces except Alberta, where potential thermal coal demand is calculated as 90 percent of the total fossil fuel requirement forecast by the ERCB in the report cited earlier.*

TABLE 50: FORECAST OF POTENTIAL COAL DEMAND IN THE CEMENT INDUSTRY, 1980 TO 2000

(10^{12} Btu)

	Total Coal	New Installations and Conversions	Existing Coal-Fired Plants
1980	47.4	37.4	10.0
1985	50.3	40.3	10.0
1990	52.4	42.4	10.0
1995	54.1	44.1	10.0
2000	53.0	43.0	10.0

TABLE 51: POTENTIAL COAL DEMAND BY THE CEMENT INDUSTRY BY REGION, 1990

(10^{12} Btu)

	Required Coal Price Discount		
	$0.40/MM Btu	$0.10/MM Btu	Total
British Columbia	4.4	-	4.4
Alberta	10.1	-	10.1
Saskatchewan	1.6	-	1.6
Manitoba	2.7	-	2.7
Ontario	11.6	5.4	17.0
Quebec	11.5	2.5	14.0
New Brunswick	-	1.0	1.0
Nova Scotia	-	1.1	1.1
Newfoundland	0.5	-	0.5
Total	42.4	10	52.4

Cement Industry Plant Locations and Share of Provincial Output

Atlantic Region - existing plant locations as in Table 45.

Quebec	St. Constant	23%
	St. Basile	9%
	Joliette	27%
	St. Michel	23%
	Villeneuve	18%
		100%
Ontario	Woodstock	9%
	Bath	16%
	Picton	24%
	Clarkson	25%
	Bowmanville	11%
	St. Mary's	15%
		100%
Manitoba	Winnipeg	100%
Saskatchewan	Regina	100%
Alberta (1981)	Exshaw	50%
	Edmonton	50%
		100%
B.C.	Kamloops	10%
	Richmond-Delta (S. Arm of Fraser)	90%
		100%

3.0 LIME

3.1 Present Energy Use

Lime is manufactured by burning or calcining limestone in kilns, mainly of rotary and vertical design. Process heat for kiln firing, by far the most energy intensive aspect of the production process, may be provided by natural gas, fuel oil, coal or petroleum coke. While vertical kilns are less amenable to coal firing than rotary kilns, the foremer are estimated to account for only 10 percent of total capacity in the Canadian lime industry. Fossil fuel consumption trends in the Canadian lime industry over the 1967-76 period is shown in Table 52.

TABLE 52: FOSSIL FUEL USE IN THE CANADIAN LIME INDUSTRY(1)

	1967		1975		1976	
	10^9Btu	%	10^9Btu	%	10^9Btu	%
Fuel oil	1,218	28	2,582	25	3,592	32
Natural gas	837	19	6,421	62	6,022	54
Coal(2)	2,348 (92.1 tons)	53	1,392 (54.6 tons)	13	1,617 (63.4 tons)	14
Total	4,403	100	10,395	100	11,231	100

(1) Source: Statistics Canada Catalogue 44-209, Lime Manufacturers.

(2) Converted on the basis of 25.5 MM Btu/Ton.

Coal was once a major fuel in the Canadian lime industry, accounting for about 53 percent of the fossil fuel use during 1967, but with the availability of low-priced natural gas its use over the past decade has dwindled to the point where it is now only a minor fuel. In June 1976, however, a new coal-fired plant owned by Steel Brothers Canada started production in Faulkner, Manitoba, resulting in the increase in coal consumption shown in Table 52. The Faulkner plant is expected to have an annual coal requirement of about 20,000 tons during a full operating year. Assuming that coal use by other producers has remained relatively constant in aggregate terms since 1975, total coal use in the lime industry presently is estimated to be in the order of 75,000 tons per year.

Lime is a very energy-intensive product as evidenced by the fact that during 1976 energy costs accounted for about 55 percent of value added in the Canadian lime industry.* For this reason one would expect that fuel choice would be largely governed by the relative cost of fuels, given the adaptability of most existing kilns to coal-firing.

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* *Statistics Canada, Catalogue 44-209 Ann., Lime Manufacturers.*

The bulk of Canadian lime production is carried out in Ontario, with a particularly large concentration of productive capacity located in the Woodstock-Kitchener region to serve the nearby steel industry at Hamilton. Table 53 shows the quantities of lime produced by province during 1976.

TABLE 53: CANADIAN LIME PRODUCTION, 1976

Province	Output M tons
B.C.	37
Alberta	146
Manitoba	100 (est.)
Ontario	1,010
Quebec	686
New Brunswick	33 (est.)
Canada	2,012

SOURCE: D.H. Stonehouse, "Lime", Canadian Minerals Yearbook, 1976 preprint, Mineral Development Sector, EMR Canada.

Future Energy Demand

In order to forecast future energy demand in the lime industry, future levels of output and energy requirements per unit of output must first be projected.

(a) Future Output

At present the iron and steel and pulp and paper industries are the two major users of lime, together accounting for about 45 percent of Canadian lime consumption in 1975. While the use of lime in other markets such as the uranium industry and sulphur dioxide removal from stack gases of coal-fired plants will undoubtedly increase over the forecast period, it is expected that the steel and pulp and paper industries will continue as the major lime markets. Forecast output of lime therefore is based upon the projected growth rates of the steel and pulp and paper industries in each provincial area as previously detailed in those sections of this study. The forecast levels of output are summarized in Table 54. From 1980 to 2000, the increase in total lime output implies on average an annual growth rate of 2.6 percent per annum, the same as that forecast for the U.S. and the rest of the world by the U.S. Bureau of Mines over the period from 1973 to 2000.*

TABLE 54: FORECAST LIME OUPUT, 1980-2000

MTPY

	1980	1985	1990	1995	2000
B.C.	39	42	45	48	52
Alberta	163	187	215	247	283
Manitoba	112	128	147	169	194
Ontario	1,146	1,341	1,570	1,838	2,151
Quebec	725	777	833	893	958
New Brunswick	33	33	33	33	33
Total	2,218	2,508	2,843	3,228	3,671

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* *Avery H. Reed, "Lime, Calcium and Calcium Compounds", Mineral Facts and Problems, 1975 edition, U.S. Bureau of Mines.*

(b) Energy Requirements per Unit of Output

Total fossil fuel use by the Canadian lime industry during 1976 was shown to be $11,231 \times 10^9$Btu in Table 52, while output during the same year was about 2,012 million tons. Energy requirements of Canadian lime manufacturers during 1976 were thus in the vicinity of 5.58×10^6Btu/ton, which is much lower than the figure of 7.79×10^6Btu/ton reportedly required by U.S. manufacturers during the same year,* even if allowances are made for the fact that the U.S. figures includes electricity consumption. Thus, the Canadian lime industry would appear to already be relatively efficient and lime manufacturers interviewed expressed the view that the scope for further efficiency gains was quite limited. A modern rotary kiln equipped with preheater requires in the order of 5.5×10^6Btu/ton, compared to as low as $3.5\text{-}4.0 \times 10^6$Btu/ton for new vertical kilns under optimal conditions. However, while vertical kilns are considerably more energy efficient than rotary kilns, the latter possess a number of offsetting advantages. These include: a superior ability to produce low-sulphur lime required for steelmaking; the complete utilization of all limestone sizes; better control of feed and temperature, resulting in a higher quality product; and higher rates of output per man-hour.* It is expected that a slight increase in the use of vertical kilns over the forecast period, combined with further improvements in the efficiency of rotary kilns will reduce average energy requirements per ton of lime to 5 million Btu's by 1990, and to 4.5 million Btu's by the year 2000.

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* *J.W. Pressler, "Lime", Preprint from 1976 U.S. Bureau of Mines Mineral Yearbook.*

** *The Conference Board, Energy Consumption in Manufacturing, Cambridge, Mass., Ballinger Publishing Co., 1974.*

(c) Forecast Energy Requirements

On the basis of forecast output as shown in Table 54, and projected energy requirements per unit of output as stated above, forecast fossil fuel requirements for the Canadian lime industry are detailed in Table 55.

TABLE 55: FORECAST FOSSIL FUEL REQUIREMENTS, LIME INDUSTRY, 1980-2000

(10^{12}Btu)

	1980	1985	1990	1995	2000
B.C.	0.2	0.2	0.2	0.2	0.2
Alberta	0.9	1.0	1.1	1.2	1.3
Manitoba	0.6	0.6	0.7	0.8	0.9
Ontario	6.2	6.9	7.8	8.7	9.7
Quebec	3.9	4.0	4.1	4.2	4.3
New Brunswick	0.2	0.2	0.2	0.2	0.2
Total	12.0	12.9	14.1	15.3	16.6

(d) Potential Thermal Coal Demand

While some lime plants, including those situated at Faulkner, Manitoba, Spragge and Beachville in Ontario, already are capable of burning coal to satisfy at least part of their kiln requirements, most plants would require significant capital expenditures in order to switch to coal as their major fuel. For an existing 100,000 ton per year rotary kiln, the capital costs of installing coal burning facilities have been placed at about $500,000 by an industry source. This amounts to about $5/ton of productive capacity and tends to confirm the range of conversion costs calculated in the cement section, given the similarity of the two industries. Based upon this figure, it was calculated in Chapter III that a price discount of $0.25/MM Btu's would be necessary to convert existing lime kilns to coal. However, since a lime producer indicated that his firm would require a higher discount of $0.40/MM Btu's, the latter figure is used in this analysis.

In order to maintain product quality in coal-fired lime kilns, most plants use coal with a sulphur content of less than 1.5 percent and an ash fusion temperature of at least 2500°F.* While lime kilns can operate entirely on coal, on the average, it is estimated that coal may be used to supply 90 percent of kiln fuel requirements, with the remaining 10 percent derived from oil or gas as backup fuels.

Potential coal demand by the lime industry is thus forecast in Table 56 by taking 90 percent of the forecast fossil fuel requirements shown in Table 55. While the total potential demand is not large compared to other industries, the relatively low coal price discount required to justify the installation of coal-burning equipment makes the lime industry one of the most promising potential coal markets. Table 57 details the potential coal demand by level of discount and region in 1990.

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* *Institute of Gas Technology, Assessment of Applications for Direct Coal Combustion, NTIS PB-263 651, October 1976, p. 148.*

TABLE 56: FORECAST OF POTENTIAL COAL DEMAND IN THE LIME INDUSTRY, 1980 TO 2000

(10^{12} Btu)

	Total Coal	New Installations and Conversions	Existing Coal-Fired Plants
1980	10.8	8.8	2.0
1985	11.6	9.6	2.0
1990	12.7	10.7	2.0
1995	13.8	11.8	2.0
2000	14.9	12.9	2.0

TABLE 57: POTENTIAL COAL DEMAND BY THE LIME INDUSTRY BY REGION, 1990

(10^{12} Btu)

	Required Coal Price Discount		
	$0.40/MM Btu	$0.10/MM Btu	Total
British Columbia	0.2	-	0.2
Alberta	1.0	-	1.0
Manitoba	0.2	0.4	0.6
Ontario	5.8	1.2	7.0
Quebec	3.3	0.4	3.7
New Brunswick	0.2	-	0.2
Total	10.7	2.0	12.7

Lime Industry Capacity Distribution

B.C.	-	Pavilion (60%), Langley (40%)
Alberta	-	Exshaw (80%), Hazell (20%)
Manitoba	-	Faulkner (75%), Fort Whyte (25%)
Ontario	-	Kitchener (75%), Sault Ste. Marie (25%)
Quebec	-	Joliette (70%), Limeridge (30%)
N.B.	-	Havelock (100%)

4.0 CHEMICALS

4.1 Historical Energy Demand

The chemical industries are major users of energy resources. While the largest component of the energy input is consumed in initiating and supporting chemical reactions and processes, large inputs are also consumed as feedstocks, or the raw materials from which chemical products are synthesized. Table 58 details consumption of energy resources as fuel and feedstock for a recent year. In addition to process energy the fuel category includes a relatively small consumption component used for ancilliary purposes such as space heating, lighting and mechanical assistance.

At the present time the chemical industries make virtually no use of coal. As indicated in Table 59 this situation marks a transition from the past. Coal traditionally had an important role as a boiler fuel, but during the 1960's coal-fired boilers were converted to gas or oil, or were replaced with new gas or oil-fired boilers. Use of coal fell from a high of 1.4 million tons in 1966, to below 100,000 tons in 1971, and to a negligible volume in 1975. In addition to supplying process energy, coal could have an important role as a feedstock in certain sectors of the chemical industry, but to date such uses in Canada have been insignificant.

Table 60 outlines the regional distribution of fuel and electricity consumption by the Canadian chemical industries. Regional data is not available on the consumption of energy resource feedstocks; however, taking into consideration the concentration of petrochemical activity in Ontario and Alberta, a moderate level of activity in Quebec, and relatively low levels of activity in Manitoba and British

TABLE 58: ENERGY RESOURCE CONSUMPTION BY CANADIAN CHEMICAL INDUSTRIES, 1974(1)

Energy Type	Fuel	Feedstock(3)	Total
		(10^9 Btu's)	
fuel oils	47,072	2,599	49,671
natural gas	90,185	51,557	141,742
LPG's, other	29,505	50,101	79,606
electricity (3)	32,926	-	32,926
	199,688	104,257	303,445

SOURCE: Statistics Canada, "Consumption of Purchased Fuel and Electricity", (Catalogue 57-208, 57-506); "Manufacturers of Plastics and Synthetic Resins", (Catalogue 46-211); "Manufacturers of Industrial Chemicals", (Catalogue 46-219).

(1) Statistics Canada feedstock data for 1975 is incomplete. See Table 59 for information on derivation methodology.

(2) At 3,412 Btu's per kilowatt hour.

(3) Comprehensive feedstock consumption data is not available from a single source. While the two sources used should cover the bulk of chemical industry consumption, an alternative aggregation of National Energy Board, Alberta Energy Resources Conservation Board and Canadian Resourcecon Limited sources indicates the total is approximately 10 percent low.

TABLE 59: ESTIMATED FUEL AND ELECTRICITY(1) CONSUMPTION IN CANADIAN CHEMICAL INDUSTRIES, 1965 TO 1975

	1965		1970		1975	
	10^9 Btu's	%	10^9 Btu's	%	10^9 Btu's	%
coal	32,245	26.3	8,425	5.5	-	-
natural gas	28,938	23.6	62,250	40.9	92,105	50.7
fuel oil:	16,350	13.3	26,988	17.7	37,927	20.9
- heavy					35,315	19.4
- others(2)					2,612	1.4
other fossil fuels(3)	22,114	18.0	20,430	13.4	24,223	13.3
electricity(4)	23,069	18.8	34,070	22.4	27,464	15.1
total	122,716	100.0	152,163	100.0	181,719	100.0

SOURCE: Derived from Statistics Canada, Consumption of Purchased Fuel and Electricity, (Catalogues 57-208, 57-506).

(1) Feedstock uses of energy resources are excluded.

(2) Includes kerosene, diesel and light fuel oil.

(3) Includes gasoline, LPG's and "other" unspecified fuels. For "other" the Btu value was derived on the basis of the "other" cost divided by the weighted average cost per unit energy for the aggregate of all specified fossil fuels. The "other" component accounts for a large portion (about 95 percent) of the other fuels category; being comprised of refinery by-products which are not normally available to most othe industrial energy users.

(4) At 3,412 Btu's per kilowatt hour.

Columbia, a regional breakdown of total energy resource consumption for 1975 is estimated to be:

Atlantic	1.5%	Prairie	1.5%
Quebec	12.0%	Alberta	19.5%
Ontario	63.0%	British Columbia	2.5%

TABLE 60: REGIONAL DISTRIBUTION OF FUEL AND ELECTRICITY CONSUMPTION BY CANADIAN CHEMICAL INDUSTRIES

	Fossil Fuels		Electricity		Total	
	10^9 Btu's	%	10^9 Btu's	%	10^9 Btu's	%
Atlantic	2,369	1.5	1,850	6.7	4,219	2.3
Quebec	14,266	9.2	8,277	30.1	22,543	12.4
Ontario	103,100	66.8	11,434	41.6	114,534	63.0
Prairie	2,177	1.4	732	2.7	2,909	1.6
Alberta	28,929	18.8	2,153	7.8	31,082	17.1
British Columbia	3,414	2.2	3,018	11.0	6,432	3.5
Total	154,255	100.0	27,464	100.0	181,719	100.0

SOURCE: Statistics Canada, Consumption of Purchased Fuel and Electricity, (Catalogue 57-208).

4.2 Future Energy Demand

The large number of chemical products produced by the Canadian chemical industries prevents separate forecasting of the output of specific products in a study of this sort. The alternative approach adopted here is to use various other forecasts of chemical industry fossil fuel (petrochemical) feedstock demand as a basis for establishing growth rate in the demand for total energy. Once the total energy demand forecast is established, consideration can be given to components of its composition, and the suitability of coal for supplying these components.

A number of mutually exclusive forecasts of demand for fossil fuel (petrochemical) feedstocks are summarized in Table 61. Total demand represents the following annual growth rates:

1975 to 1985	13.3 percent
1985 to 1990	3.5 percent
1990 to 2000	0.1 percent

The very high growth rate over the 1975 to 1985 period is induced by four major developments in the chemicals industry; commissioning of:

- the Petrosar plant
- three large ammonia plants in Alberta
- the Alberta petrochemical complex
- new methanol units in Alberta

These developments alone account for an increase of over 150 billion Btu's per annum in feedstock requirements.

In relating fuel demand of the chemical industries to fossil fuel (petrochemical) feedstock demand, the fuel category may be divided into two broad components. The first involves fuel demand related directly to utilization of (petrochemical) feedstocks. Included will be requirements for synthesizing the chemical derivative from the feedstock, and subsequently for various stages of upgrading the derivative to its final market form. For the purpose of developing a forecast it is estimated that in 1974 the fuel and electricity consumed in synthesis and upgrading of petrochemical feedstocks had equal thermal value to the feedstocks themselves. The remainder of energy resource consumption may then be attributed to non-petrochemical chemicals production to give the following breakdown (from Table 58):

TABLE 61: FORECAST DEMAND FOR FOSSIL FUEL PETROCHEMICAL FEEDSTOCKS, 1975 TO 2000

	Petroleum	Alberta Gas and Coal	Ontario Gas	Other Gas	Total
			(10^9 Btu's)		
1975	84,400	23,600	8,300	3,500	119,800
1980	187,500	97,400	9,800	3,500	298,200
1985	290,800	113,200	10,700	3,500	418,200
1990	338,500	142,600	11,600	3,500	496,200
1995	338,500	147,900	12,200	3,500	502,100
2000	338,500 est.	145,700	13,000	3,500	500,700

SOURCE: Petroleum: National Energy Board, Canadian Oil Supply and Requirements, September, 1978 and February 1977;
Alberta Gas: Alberta Energy Resources Conservation Board, Energy Requirements in Alberta, 1976-200, September 1978;
Ontario Gas: Canadian Resourcecon Limited, Foreast of Industrial Natural Gas Demand in Ontario and Quebec, 1976-2000, June 1978;
Other Gas: estimated on the basis of 175,000 tons of ammonia (Cominco-Trail and Simplot-Brandon) requiring 20 Mcf of feedstock per ton.

	trillion Btu's
- petrochemical feedstocks	104
- petrochemical fuel and electricity	104
- non-petrochemical chemicals fuel and electricity	96

Growth rates developed from Table 61 and outlined above are used for calculating the forecast demand for petrochemical feedstocks as summarized in Table 62.* While petrochemical feedstock is assumed to equal petrochemical fuel and electricity in thermal value in 1975, this relationship is not expected to be maintained. During the mid and late 1970's the chemical industry has undertaken widespread and major steps to improve energy efficiency. The industry through its Task Force on Energy Conservation set a goal of 17 percent reduction in energy resource input per unit of output for the period of 1972 to 1980. Preliminary results indicate the goal will be achieved.** Some of the conservation benefits may be achieved in feedstock utilization, but the majority are expected to relate to utilization of fuel and electricity. Thus, the relationship between feedstock, and fuel and electricity components is estimated to change:

- from 1.0 to 1.0 in 1975;
- to 1.0 to 0.8 in 1980;
- to 1.0 to 0.7 in 1985 and thereafter.

This change is reflected in the petrochemical fuel and electricity column of Table 62.

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* *To compensate for the decline in fuel and electricity consumption from 1974 to 1975 (Tables 58 and 59), the 1975 base levels used for calculation of future requirements are lagged to 1974 values.*

** *Chemical Industry Task Force on Energy Conservation, Energy Conservation Report, and letter to the Minister of Industry, Trade and Commerce, March 30, 1977.*

TABLE 62: FORECAST CHEMICAL INDUSTRY ENERGY RESOURCE REQUIREMENTS IN CANADA, 1980 TO 2000

	Petrochemicals			Non-Petrochemicals	
	Feedstock	Fuel & Elec.	Sub-Total	Fuel & Elec.	Total
			(10^{12}Btu's)		
1975	104	104	208	96	304
1980	194	155	349	111	460
1985	363	254	617	129	746
1990	431	301	732	142	874
1995	433	303	736	157	893
2000	435	304	739	174	913

SOURCE: Canadian Resourcecon Limited.

The non-petrochemical sector of the chemical industry is unlikely to achieve the rapid rate of growth of the petrochemical sector in future years. Generally, the non-petrochemicals sector had reached a higher level of maturity and diversity by 1975 than had the petrochemicals sector. Further specific highly energy intensive elements of the sector such as the chlor-alkali industry are expected to undergo relatively low future growth rates. Energy requirements of the non-petrochemical sector are estimated to grow at an average annual rate of 3.0 percent to 1985 and 2.0 percent thereafter. These requirements are summarized in Table 62.

4.3 Potential Thermal Coal Demand

As discussed earlier in this section, coal was formerly an important fuel in chemicals production. During the past decade, however, coal burning equipment has been almost entirely converted to or replaced by oil and gas fired equipment. New facilities have been desgined and constructed for oil or gas or in some cases with provision for both. During investigations for this study no situations were encountered in which new facilities were built with provision for coal, or major energy consuming old facilities with former coal capability could readily convert back to coal.

Comprehensive analysis of conversion costs to coal by the chemical industry, or of the required discount per unit energy for coal relative to other energy types is unavailable. However, discussion with industry representatives indicates the industry generally feels that present fuels could bear significant cost penalties before conversion of existing installations or coal designs for new installations would be considered. The following points summarize some of the concerns of the industry:

(i) any existing investment in non-coal equipment which would be lost through conversion would accrue as a conversion cost. These investments and resulting costs could be substantial;

(ii) conversion costs would tie-up capital which might otherwise be used for expansion, but conversion would not add to production. The industry tends to be capital intensive and lack of availability of capital can constrain expansion;

(iii) efficiency of many processes is highly sensitive to precisely controlled conditions. These conditions would be difficult to obtain with coal, or in some instances, from a practical viewpoint, would be unobtainable;

(iv) fuels or fuels and feedstocks for chemical operations often flow from other energy processing operations. Chemical uses are the most advantageous or only use for these materials and use of coal would reduce or eliminate the value of the present fuel or feedstock.

The complexity of even a conversion of chemical plant boilers is indicated in a DuPont submission to the 1974 National Energy Board natural gas hearing:

> "Preliminary information indicates that to change over to coal, it would probably be necessary to build new power-houses at each of our sites, at

> a cost of 20 million dollars "(1973 or 1974$)" or more. This amount of money is over 5% of the capitalization of the Company, and would not add to our manufacturing capability. Such a program would require at least three years to implement."*

Discussion with chemical industry representatives gave the general impression that lack of availability of detailed information on conversion costs to coal is a result of a "feel" for the magnitude of additional costs associated with coal rather than a desire to maintain confidentiality of more precise information.

Lacking conversion cost information from the chemical industry, it is necessary to estimate required price discounts for coal relative to other energy resource types on the basis of interpretation of more general information. Conversion costs and price discounts for steam plants and process heaters are outlined on pages 41 to 49. Required discounts of $1.39 to $2.21 and $0.94 to $1.65 per million Btu's are calculated for conversion and new installation situations respectively. In the case of the chemical industries it is assumed that all fuel and electric requirements forecasts to 1982 would be in a conversion category; all incremental requirements beyond 1982 would be a new installation category. However, not all forecast energy requirements are substitutable. Some special processes in the chemical industries require particular fuels and coal is unlikely to be used as a substitute regardless of foreseeable energy prices. In the petrochemical sector of the industry various fuels will be used because of their in-company availability and generally unmarketable characteristics -- in effect the price of these fuels will be significantly below the gas and heavy fuel oil prices forecast for other industrial consumers (Chapter III) Other non-substitutable uses will include electric lighting and mechanization, and may include electric requirements for electrolysis. In aggregate non-substitutable energy requirements are estimated to total 35 percent of total fuel and electric requirements. Table 63 outlines substitutable and non-substitutable and conversion and new installation components of chemicals industry fuel and electricity demand.

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* *DuPont of Canada Limited.*

TABLE 63: FORECAST OF POTENTIAL COAL DEMAND BY THE CHEMICAL INDUSTRIES, 1980 TO 2000

	Total Fuel & Elec.	Substitutable Fuel & Elec.	Conversion Situations	New Installation Situations
		(10^{12} Btu's)		
1980	266	172	172	-
1985	383	249	200	49
1990	443	288	200	88
1995	460	299	200	99
2000	478	311	200	111

SOURCE: Canadian Resourcecon Limited.

Energy resource requirements for petrochemical feedstocks must be considered separately from the fuel and electricity requirements of the chemical industries. While most, if not all, feedstocks could be derived from coal the cost of doing so would be quite high. Before synthesis of the petrochemical product it would generally be necessary to synthesize a product from the coal similar to the normal process feedstock. While investigation of coal derivation of petrochemical feedstocks has not been undertaken on a product by product basis during the course of the study, it is judged that the cost of the derivation process, plus the cost of the coal, would exceed the cost of the normal feedstock. Thus, it is concluded that significant use of coal feedstocks for petrochemicals production is unlikely in Canada before the year 2000, and no potential coal demand is recognized.

In assessing potential demand for coal by the chemical industries it is noteworthy that the Alberta Energy Resources Conservation Board has recently recognized as a provincial energy requirement a supply of coal for three new ammonia plants which are forecast to come on stream between 1984 and 2001.* Coal requirements are forecast at the following levels:

	10^6 tons	10^{12} Btu's**
1985	1.2	19.2
1990	1.2	19.2
1995	2.0	32.0
2000	2.6	41.6

This provision of coal appears to indicate intended policy for disposition of energy resources. No detail is provided to show that analysis of gas and coal alternatives has indicated the use of coal will be economically advantageous to the producer. In the case of the fuel component of energy resource demand, new ammonia plants are included in this study in the incremental requirements column of Table 63; however, as stated above no potential feedstock demand is recognized.

Regional estimates of chemical industry energy consumption for 1975 are outlined in Table 60. With the major expansion of petrochemical activity in Alberta, and a diversification of regional chemicals activity outside Ontario, the Ontario share of Canadian chemicals activity will decline in future years. Other regions are all likely to increase their shares of national activity, with particularly strong growth to be expected in Alberta. By 1990 the regional distribution of energy demand of the chemical industries is forecast to evolve to the following pattern:

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* *Alberta Energy Resources Conservation Board, Energy Requirements in Alberta, 1977-2006, September 1978.*

** *At 16.0 million Btu's per ton.*

Atlantic	3.0	Prairie	2.0
Quebec	15.5	Alberta	25.0
Ontario	50.0	British Columbia	4.5

Estimates of regional distribution of potential chemical industry coal demand for 1990 are outlined in Table 64, taking into account conversion and new installation situations as the regional pattern of chemicals activity in Canada evolves.

TABLE 64: POTENTIAL COAL DEMAND BY THE CHEMICAL INDUSTRY BY REGION, 1990

	Required Coal Price Discount(1)		
	$1.55/MMBtu's	$1.15/MMBtu's	Total
	(10^{12} Btu's)		
Atlantic	4.5	4.1	8.6
Quebec	27.5	17.1	44.6
Ontario	113.0	31.0	144.0
Prairie	3.5	2.3	5.8
Alberta	44.5	27.5	72.0
British Columbia	7.0	6.0	13.0
Total	200.0	88.0	288.0

SOURCE: Canadian Resourcecon Limited.

(1) Based on 200,000 pound per hour steam plant.

5.0 STEEL INDUSTRY

The steel industry category described in this section consists of those firms which produce raw steel and transform it into primary market shapes through hot and cold rolling processes. For statistical purposes the steel industry discussed here includes those activities within the Standard Industrial Classification category 291.

5.1 Industry Structure and Output

(a) Present and Historical

(i) Growth of output

The output of the Canadian steel industry has grown from 5.8 million net tons in 1960 to 14.4 million net tons in 1976, an average annual growth rate of 6.1 percent over the period (see Table 65). Over the last ten year period, 1965 to 1975, the average growth rate of output has been considerably lower at 4.9 percent per year.

The production of steel product in Canada is concentrated in three vertically integrated companies in Ontario: Stelco, Dofasco, and Algoma. The Ontario operations of these three firms account for approximately 78 percent of Canada's steel output.*

The Ontario operations of these three producers, plus a comparatively small output from smaller Ontario operators such as Slater Steel Industries, and Lake Ontario Steel, are responsible for over 80 percent of Canada's steel production** (Table 65).

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* *Ontario Hydro, Energy Use in the Iron and Steel Mills in Ontario, 1975, p. 4.*

** *Statistics Canada 41-203, Iron and Steel Mills.*

TABLE 65: ANNUAL PRODUCTION OF STEEL INGOTS AND STEEL CASTINGS, ONTARIO AND CANADA, 1960-1975

	Canada (000 tons)	Ontario (000 tons)	% Can.
1960	5,809	4,609	79.3
1961	6,488	5,431	83.7
1962	7,173	5,965	83.2
1963	8,197	6,753	82.4
1964	9,128	7,581	83.0
1965	10,068	8,485	84.3
1966	10,020	8,453	84.4
1967	9,701	8,333	85.9
1968	11,251	9,400	83.6
1969	10,307	7,960	77.2
1970	12,346	10,129	82.0
1971	12,170	10,010	82.3
1972	13,073	10,768	82.4
1973	14,755	12,040	81.6
1974	15,017	11,926	79.4
1975	14,357	11,652	81.2
Average Annual Growth Rates (1)			
1960-1975	6.1%	5.8%	
1965-1975	4.9%	4.3%	
1970-1975	4.4%	3.8%	

(1) *For Canada and Ontario best fit straight lines were plotted for all three time periods on an arithmetic plot. The average annual growth rates which are shown are rates which would achieve the same increases over each time period as were achieved by the arithmetic plots.*

SOURCE: Statistics Canada 41-203, Iron and Steel Mills.

(ii) Steel making technology

In Canada, at the present time, four processes are used to produce steel. They are:

- blast furnace plus open hearth furnace
- blast furnace plus basic oxygen furnace (BOF)
- scrap plus electric arc furnace
- directly-reduced iron ore plus electric

The first two processes are traditional, involving a two-stage process, in which iron ore is first converted to liquid iron in a blast furnace and then refined into steel in an open hearth furnace or basic oxygen furnace. It is well established that the BOF process is more economic than the open hearth, but the open hearth furnace is more flexible in the use of scrap iron than the BOF. The third process utilizes an electric arc furnace to melt scrap iron and, in fact, is limited by the availability and price of scrap iron and the cost of electric power. The last process, direct reduction, produces a solid sponge iron instead of liquid iron, which can be used in an electric arc furnace to produce steel or can be fed into BOF or open hearth furnaces as a substitute for scrap.

The BOF process is similar in principle to the open hearth concept with the exception that oxygen is forced or blown into the furnace charge during the melting cycle, "burning" out hot metal impurities with no additional fuel being used for scrap melting. In the open hearth furnace energy is used to (1) melt down the extra scrap charged with the hot metal (open hearth has traditionally charge a higher percentage of scrap than BOF) and (2) to keep the open hearth hot, due to long refining time (oil or gas is blown over the charge). The hot metal arriving from the blast furnace to BOF requires only oxygen to convert pig iron to steel. The BOF is able to convert molten iron (pig iron) from a blast furnace into steel in about 45 minutes, compared with about 10 hours in the open hearth. The electric arc furnace requires about three hours from a cold start.

There are currently 3 direct reduction facilities in Canada, each based upon a different process. The largest plant, operated by Sidbec-Dosco in Contrecoeur, Quebec, uses natural gas as the reductant in its Midrex process shaft furance. This process is not considered amenable to the substitution of coal. In Ontario there are two direct reduction facilities - one at Bruce Lake owned by Stelco and one at Sudbury, owned by National Steel Corp. and Allis Chalmers Corp. Stelco's plant, which has not operated since August 1976 due to the price of scrap being lower than the cost of producing directly-reduced iron, uses coal as the reductant in its 350,000 tonne per year SL/RN rotary kiln. The Sudbury operation, with an SL/RN rotary kiln modified by Allis Chalmers, is rated at 300,000 tons per year. It uses oil and gas as reductants at present and may eventually use coal.* This kiln has also been idled recently due to low scrap prices.

At present, the bulk of the steel production in Ontario is melted by the BOF process. For example, in 1975, 69 percent of Ontario's steel was produced in BOF's, 25 percent in open hearth furnaces, and 6 percent in electric furnaces. The production of raw steel by type of furnace in Ontario for the years 1964 to 1975 is shown in Table 66.

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* *Michel A. Boucher, "Iron Ore", Canadian Minerals Yearbook, 1976 preprint Mineral Development Sector, EMR Canada, p. 9.*

TABLE 66: RAW STEEL PRODUCTION IN ONTARIO, 1964-1975 (million tons)

Year	Open Hearth	BOF	Electric	Total
1964	4.4	2.8	.4	7.6
1965	4.7	3.2	.6	8.5
1966	4.5	3.4	.6	8.5
1967	4.5	3.2	.6	8.3
1968	5.2	3.5	.6	9.4
1969	4.3	3.2	.6	7.9
1970	5.9	3.6	.6	10.1
1971	5.4	3.9	.7	10.0
1972	4.3	5.6	.9	10.8
1973	3.8	7.4	.9	12.1
1974	3.0	8.1	.8	11.9
1975	2.9	8.1	.7	11.7

SOURCE: Acres Consulting Services Limited, Ontario Industrial Energy Demand Study, February 1977, p. 152.

Oxygen steel production surpassed open-hearth production for the first time in 1972; conversely, while the relative capacity of the basic oxygen furnace has been expanding steadily, the open hearth furnace production level has declined from a peak of 5.2 million tons in 1968 to 2.9 million tons in 1975.

Small capacity gains have been made over the past 10 years by electric steelmakers. However, most of the electric furnace capacity increases in Canada have occurred in Quebec and the Western Provinces.

(b) Future Growth

The Department of Energy, Mines and Resources has forecast Canadian consumption of steel ingots and castings to grow to 35,485,000 tons* by the year 2000** as follows:

	Consumption 000 tons	Average Annual Growth Rate %
1975	14,964 (act.)	
1980	20,756	6.8
1985	25,646	4.3
2000	35,485	2.2

Although steel production in Canada in 1976 and 1977 has grown very little from 1975 levels, we have nevertheless adopted EMR's forecast as being a reasonable estimate of steel demand over the longer term.

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* *Short tons.*

** *Energy, Mines and Resources, Canada, Operators List 2, Metallurgical Works in Canada, Primary Iron and Steel, January 1977, p. 5.*

The assumption is made that Canada will maintain its position as a net importer of steel at the 1975 level of 4.1 percent of domestic apparent consumption; this is a reasonable average figure based on historical experience over the past 16 years. The same EMR growth rates used for projection of apparent Canadian steel consumption are therefore used to forecast future Canadian production levels. Table 68 details this forecast and shows total Canadian steel production increasing from 14.4 million tons in 1975 to 34.0 million tons by the year 2000.

Ontario's share of Canadian production, as illustrated in Table 65, has been over 80 percent in most of the years between 1960 and 1975; Ontario produced 81.2 percent of Canadian steel in 1975. The assumption in this report is that Ontario's position as Canada's major supplier of steel will be eroded slightly in the future; its share of Canadian production will fall to 75 percent of the Canadian total by the year 2000. This relative decline of Ontario production to the Canadian total will of course be matched by a correspondingly greater share of output in other regions of Canada; in our view regional interests will dictate the expansion of steelmaking capacity in Western Canada and Quebec relative to that in Ontario.

Ontario's production of steel will therefore grow at a slightly slower rate than the Canadian average; output in volumetric terms will still be very large however, increasing from 11.7 million tons in 1975 to 25.5 million tons by 2000 (Table 67).

The Ontario steel industry is forecast to remain largely dedicated to the blast furnace - basic oxygen furnace technology. Production of steel by open hearth furnace is expected to be terminated

TABLE 67: FORECAST PRODUCTION OF STEEL INGOTS AND CASTINGS, CANADA AND ONTARIO, 1975-2000

Year	Canada	Ontario	
	000 tons	000 tons	% Production
1975 (actual)	14,357	11,652	81.2
1976 (actual)	14,480	12,529	81.0
1977	16,580	13,380	80.7
1978	17,692	14,242	80.5
1979	18,803	15,080	80.2
1980	19,915	15,932	80.0
1981	20,853	16,620	79.7
1982	21,792	17,325	79.5
1983	22,730	18,002	79.2
1984	23,669	18,699	79.0
1985	24,607	19,366	78.7
1986	25,236	19,810	78.5
1987	25,866	20,227	78.2
1988	26,495	20,666	78.0
1989	27,124	21,075	77.7
1990	27,753	21,508	77.5
1991	28,383	21,912	77.2
1992	29,012	22,339	77.0
1993	29,641	22,734	76.7
1994	30,270	23,156	76.5
1995	30,900	23,546	76.2
1996	31,529	23,962	76.0
1997	32,158	24,344	75.7
1998	32,787	24,754	75.5
1999	33,416	25,129	75.2
2000	34,046	25,534	75.0

by 1990. It is assumed that electric steelmaking furnaces will continue to produce about eight percent of the province's total output to the year 2000.

(b) Energy Use

(i) Present Energy Demand

Metallurgical coal is the dominant source of energy in steelmaking. Coke, which is derived from coal, fuels the blast furnaces which produce molten iron. The coal-coke cycle also generates by-product fuels such as coke oven gas, which are recycled to meet a major portion of the non-blast furnace fuel needs of a steel mill. Natural gas and fuel oil are generally used for heat treating and reheating functions and for blast furnace injection. These two fuels are also used in partially fueling open hearth furnaces and boilers to supplement recovered by-product fuels. Principal applications of electrical energy in steelmaking are for powering mill equipment and for electric arc furnaces.

The past decade has witnessed the curtailment of the use of thermal coal as a fuel in the iron and steel industry. In approximate terms, 100,000 to 200,000 tons were consumed annually until 1970, shortly after which thermal coal use ceased altogether (see Table 68). The figures in Table 68 show the extent to which changes have occurred in the use of specific fossil fuels.

Since natural gas, fuel oil and coal have different physical properties, it is difficult to totally substitute one fuel for another in particular applications. Apart from metallurgical coal, the industry is not overly dependent on other fossil

TABLE 68: FOSSIL FUEL AND ELECTRIC ENERGY USE, STEEL INDUSTRY, ONTARIO, 1964-1975

	Steel Production	Natural Gas		Fuel Oil		Thermal Coal		Electric Energy trillion Btu	Total Fossil Fuel (million Btu/ton)
	000 tons	trillion Btu	% Fossil Fuel	trillion Btu	% Fossil Fuel	trillion Btu	% Fossil Fuel		
1964	7,581	8.3	21.6	26.7	69.3	3.5	9.1	7.4	5.07
1965	8,485	10.6	23.9	29.1	65.6	4.6	10.4	8.4	5.22
1966	8,453	12.0	26.2	28.5	62.2	5.3	11.6	9.0	5.43
1967	8,333	12.7	27.8	29.3	64.1	3.7	8.1	9.0	5.49
1968	9,401	15.5	37.1	22.9	54.8	3.4	8.1	9.7	4.45
1969	7,960	16.5	43.0	19.2	50.0	2.7	7.0	9.8	4.83
1970	10,129	21.6	48.5	22.1	49.4	0.9	2.1	10.8	4.40
1971	10,010	26.3	60.2	17.0	38.9	0.4	0.9	11.1	4.37
1972	10,768	30.9	67.3	15.0	32.7	-	0	11.8	4.26
1973	12,040	34.9	76.7	10.6	23.3	-	0	12.6	3.78
1974	11,926	37.5	74.0	13.2	26.0	-	0	12.6 est.	4.25
1975	11,652	36.3	76.9	10.9	23.1	-	0	12.2	4.05

SOURCE: Statistics Canada, CANSIM.
Acres Consulting Services Ltd., Ontario Industrial Energy Demand Study, Ontario Ministry of Energy, 1977.

fuels. Over the past years each of the major steelmakers has developed unique processes, which have associated with them, unique fuel requirements. While interchangeability between fuels is theoretically possible, interfuel substitution would ential substantial capital outlays which may or may not be recovered by energy cost savings obtained by switching from one fuel to another.

The decline in thermal coal was predicated on the belief that low-cost supplies of natural gas would be available in Canada over the long term. With the recent rapid escaltion in fuel prices, steelmakers are making concerted efforts to find ways of using energy more efficiently, and as well are investigating opportunities which would enable the substitution of lower-cost fuels.

(ii) Potential Thermal Coal Demand

One of the most promising substitution possibilities involve the use of a coal-tar slurry (instead of oil or natural gas(for blast furnace injection. This scheme, under study by Stelco, would involve blending tar, a by-product of this coke making process, with thermal coal. While this technology has not been applied on a commercial scale, Stelco is confident of its feasibility. Based upon preliminary analysis, this alternative looks attractive when compared with current natural gas and fuel oil prices. Since the delivered price of U.S. bituminous coal to large industrial users in Southern Ontario is about $0.75 per MM Btu's cheaper than that of oil or natural gas, it is felt that a price discount of this magnitude is sufficient to encourage the use of coal in this application.

According to Stelco, use of a coal-tar slurry in the company's blast furnaces would entail the use of about 3.5 trillion Btu of coal annually. If Dofasco and Algoma also exploited this substitution possibility, the requirement for coal would be roughly 8.8 trillion Btu per annum, based upon presently-installed capacity. Based upon the expectation that blast-furnace steelmaking will continue to maintain its share of output, it is forecast that this thermal coal market will increase in porportion to steel output as projected earlier. Considering that this technology is still in the development stage, however, it is doubtful whether there would be much impact upon coal demand before 1985. Forecast thermal coal demand for blast furnace injection is shown in Table 69.

A second major thermal coal market in Ontario will develop in the two existing direct reduction kilns (previously described) when scrap prices rise sufficiently to make their operation profitable. The Stelco plant would require a minimum of 5.0 trillion Btu's of coal per annum at full production, while the plant at Sudbury would consume about 4.3 trillion Btu's if converted to coal at full output, based upon an estimated minimum energy requirement of 13 million Btu/ton for both plants.*

It is forecast that Stelco's plant will be back in operation by 1980, or shortly thereafter. Since this facility was designed to burn coal, a coal price discount would not be required to continue its use. The Sudbury plant, on the other hand, would require a discount, probably in the order of $0.75 per million Btu's, in order to convert to coal use. Conversion of this plant to coal will likely occur by 1990,

* *Boucher, op.cit., p. 16.*

given a discount of this magnitude. Since the growth of direct reduction capacity is considered more likely to take place in regions of Canada other than Ontario, where integrated steelmaking is centred, it is expected that direct reduction and requirements will be limited to the needs to those two plants.

Forecast thermal coal demands in the Ontario steel industry are summarized by end use in Table 69 and by level of discount in Table 70.

TABLE 69: POTENTIAL THERMAL COAL DEMAND BY END USE, ONTARIO STEEL INDUSTRY, 1980-2000 (10^{12} Btu)

	Blast Furnace Injection	Direct Reduction	Total
1980	-	5.0	5.0
1985	5.0	5.0	10.0
1990	10.0	9.3	19.3
1995	15.0	9.3	24.3
2000	20.0	9.3	29.3

TABLE 70: POTENTIAL THERMAL COAL DEMAND BY LEVEL OF DISCOUNT, ONTARIO STEEL INDUSTRY, 1980-2000 (10^{12} Btu)

	Total Potential Coal Demand	Required Coal Price Discount $0.75/MMBtu	Nil
1980	5.0	-	5.0
1985	10.0	5.0	5.0
1990	19.3	14.3	5.0
1995	24.3	19.3	5.0
2000	29.3	24.3	5.0

5.2 Saskatchewan

With expectations of strong steel demand in western Canada over the next decade, the government of Saskatchewan is considering giving support to the construction of a direct reduction plant in Regina with operation to begin in the early 1980's. The plant would have an annual production capacity of about 600,000 tonnes of sponge iron, with the bulk of the output expected to be used by the IPSCO steel plant at Regina, and to a lesser extent by Manitoba Rolling Mills at Selkirk, and Western Canada Steel in Calgary.* It is assumed here this capacity would be increased to 1,000,000 tonnes in 1995 and that the facility would continue to function as a merchant mill supplying all steel makers in western Canada.

A coal based direct reduction facility producing 600,000 tonnes of sponge annually would require at least 8.6 trillion Btu of coal per year.** While the precise level of discount required to economically justify the selection of coal in preference to other reductants is not known, it will be estimated at $0.50/MMBtu. The planned Saskatchewan direct reduction facility could consume about 8.6 trillion Btu of thermal coal annually from 1985 to 1995, increasing to 13.0 trillion Btu in 1995.

	Total Potential Coal Demand	Required Coal Price Discount $0.50/MMBtu
1980	-	-
1985	8.6	8.6
1990	8.6	8.6
1995	13.0	13.0
2000	13.0	13.0

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* *Michel A. Boucher, "Iron Ore", Canadian Minerals Yearbook, 1977 preprint, Mineral Policy Sector, EMR Canada.*

** *At 13 million Btu/ton - see Ontario section.*

5.3 Other Provinces

There are small regional steel making industries in both Quebec and Nova Scotia. The Quebec industry, however, is entirely based upon electric steel making, with scrap and directly-reduced sponge iron providing the raw materials for the electric furnaces. No significant coal market is foreseen in the Quebec steel industry, however, since the Midrex process used by Sidbec Dosco requires natural gas as a reduction and is not amenable to substitution by coal.

While the Nova Scotia steel mill at Sydney is based upon the blast furnace process, an official contacted at the mill could not envision the use of coal-tar slurry blast furnace injection for two reasons: First, the mill is struggling for survival and the capital expenditure required for such a conversion would probably not be forthcoming. Secondly, a contract with Domtar guarantees the mill a price for its tar which is based upon the cost of heavy fuel oil plus a premium. Hence, the mill has no strong incentive to reduce the present use of heavy fuel oil for blast furnace injection.

6.0 OIL SANDS

The oil sands deposits cover large areas of Alberta to the north and east of Edmonton. Where overburden is shallow, such as adjacent to the Athabasca River in the vincinity of Fort McMurray, surface mining methods are used to "mine" the oil sands and transport them to an extraction plant where separation of the bitumen from the sand is effected. Where overburden is deeper such as in the Cold Lake area (900 to 1600 feet of overburden) recovery will be achieved by in situ production methods.

At the present time two surface mining ventures are operational in the Athabasca deposit north of Fort McMurray, that of Great Canadian Oil Sands producing at a level of approximately 50,000 b/d and Syncrude's with a projected production level of 130,000 b/d. Additional oil sands plants, both surface and in situ, are forecast to be constructed over the forecast period with output predicted to reach over 1,000,000 b/d by 2000 (Table 71).

6.1 Mining Projects

a) Great Canadian Oil Sands

GCOS consumes about 5 Bcf annually for fuel and feedstock purposes. They hope to reduce this quantity to 3 or 3.5 Bcf/yr. (assuming constant plant output at 45,000 b/d) through better recovery of their own process produced gas. GCOS gas requirements will however likely remain at approximately 5 Bcf/annum over the forecast period on the basis of a plant expansion to 60,000 b/d achieved by 1981. Coal is not forseen to be an economic substitute for natural gas in this operation.

TABLE 71: FORECAST OF OUTPUT FROM OIL SANDS PLANTS
ALBERTA 1980-2000

	Plant Description		Output* b/d
1980	GCOS		50,000
	Syncrude		130,000
1981	GCOS addition		15,000
1984	Syncrude addition		70,000
1986	Shell Canada		125,000
1987	Cold Lake		145,000
1990	Second in situ		145,000
1993	Fourth mining		125,000
1997	Third in situ		145,000
2000	Fifth mining		125,000
	Total Output, 2000	=	1,075,000

SOURCE: Canadian Resourcecon Limited.

* *The National Energy Board "base case" forecast of oil sands production in 1995 is some 750,000 b/d compared to a figure of 805,000 b/d in 1993 in this estimate. NEB, Canadian Oil Supply and Requirements, September 1978, p. 63.*

b) Syncrude

Syncrude has a much higher natural gas consumption per unit of output than GCOS. This is in large part due to the fact that Syncrude does not use coke as a boiler fuel as does GCOS.

Natural gas is used as the feedstock for the manufacture of hydrogen in bitumen upgrading. The hydrogen synthesis reaction is as follows:

$$CH_4 + 2H_2O \longrightarrow CO_2 + 4H_2$$

One cubic foot of natural gas yields 4 cubic feet of hydrogen (½ the hydrogen is seen to come from water). Assuming 1400 cubic feet of hydrogen per barrel of upgraded crude* leads to a requirement of 350 cubic feet of gas per barrel; at Syncrude's target capacity of 130,000 b/d this would result in a natural gas requirement of approximately 16.6 Bcf/yr.

Outside fuel used by Syncrude at capacity is estimated at 225 cft/bbl. of product, equivalent to 10.3 Bcf/year. With further increases forecast in the real price of natural gas, Syncrude may replace natural gas as a fuel with coal or a low or medium Btu gas produced from coke; the assumption here is that coke gasification would be the chosen alternative and not coal. As Syncrude has constructed a natural gas steam methane reformer for the manufacture of hydrogen, it is predicted that natural gas will continue as feedstock for H_2 production over the full forecast period.

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* *Estimate based on discussion with Imperial Oil personnel.*

c) Future Mining Plants

Mining projects are largely self sufficient in energy supply assuming the utilization of coke either to produce hydrogen or to be gasified for use as a boiler fuel.

The Shell surface mining project (Alsands) currently being planned envisages a fluid coking operation for bitumen upgrading; coal is not being considered as an energy source. Sufficient coke would be produced to satisfy the plant requirements for H_2 through a partial oxidation of coke process. Offgases produced by the fluid coker would provide the bulk of the fuel requirements for power generation and all plant processes. An auxiliary fuel (fuel oil or natural gas) would be required for short periods of time when the upgrading operation is not in balance with the extraction process; however coal would not be a substitutable fuel on such occasions in the boilers and process units designed for off gas utilization.

Thus no coal use is forecast in future oil sands mining operations.

6.2 In Situ Projects

In situ projects have a much higher energy requirement per barrel of product produced than mining projects; because of the lower recovery efficiency of in situ plants compared to surface operations much more oil sands material is heated per barrel of product recovered. In situ operations cannot achieve an energy balance from the coke and C_3 minus gases produced in the bitumen upgrading operation, and a supplemental outside fuel, or a portion of the heavy oil material itself which is recovered must be consumed also. Imperial Oil are considering the use of coal from their own Judy Creek coal property as the supplemental fuel source in their proposed Cold Lake project, projected to produce 145,000 b/d of product. The coal requirement would be 2.6 million short tons of Judy Creek coal [illegible] a colorific value of 6500 Btu/lb.*; this is equivalent to 33.5 x 10^{12} Btu/annum of input energy. It will be assumed in this analysis that at a discount of $0.75/MMBtu from prevailing gas prices coal will be the choice of supplemental fuel at in situ projects. Potential coal demand is thus forecast at approximately 100 x 10^{12} Btu/year by the year 1997 (Table 72) when the third in situ plant is forecast to come on stream.

TABLE 72: POTENTIAL COAL DEMAND, OIL SANDS PLANTS 1978-2000

	Project	Potential Coal Demand 10^9 Btu
1987	Cold Lake (I.O.)	33,500
1990	Second in situ	67,000
1997	Third in situ	100,500**

** *Equivalent to nearly 8 million tons/year of coal with a colorific value of 6500 Btu/lb. The Alberta Energy Resources Conservation Board in their recent report, "Energy Requirements in Alberta, 1977-2006, Sept. 1978, forecast coal requirements for in situ operations at 8.2 million short tons per year by 2000.*

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* *Esso Minerals Canada, Application to the ERCB to Develop and Operate The Judy Creek Coal Mine, June 1978.*

7.0 SMELTING AND REFINING

The smelting and refining sector consists of firms engaged in the smelting of ores bearing non-ferrous metals and/or the refining of non-ferrous metals. The industry produces a diversity of products ranging from lead to precious metals; however, nickel, copper, zinc and aluminum are by far the most important in dollar value terms. While the following analysis will deal largely with the production of these metals, the energy use figures which are presented relate to the production of all types of non-ferrous metals.

7.1 Process Description

A variety of metallurgical processes are employed in the metal smelting and refining industry. This analysis reviews in general terms the way in which mineral ores and concentrates are upgraded to nickel, copper, zinc and aluminum. The methods used to smelt and refine nickel and copper are generally similar; hence, a single process description is presented for these, while zinc and aluminum are treated separately.

a) Smelting

i) Nickel and Copper

The smelting of non-ferrous metals generally consists of three operations:

- roasting
- smelting
- converting.

Nickel and copper concentrates are first of all processed in a roasting furnace to oxidize the iron content of the ore. Roasting is done in multi-hearth or fluidized bed roasters, although use of the former is declining because of associated high capital, operating, and maintenance costs.* The roasting phase is not significant from an energy use standpoint as the oxidation of iron involves an exothermic reaction requiring no external fuel use.

The output of the roaster, referred to as calcine, is then thermally treated in a furnace to segregate desirable from unwanted constituents. Smelting is generally done in either a reverberatory, electric, or flash furnace. In the reverberatory furnace the calcine is heated to a melting temperature using pulverized coal or residual oil as a fuel; natural gas is not as desirable a fuel in this process because of its flame and heat transfer properties. In electric matte smelting electrodes are submerged in the slag layer; the slag impedes the flow of electric current and heat is generated; the resultant high temperature leads to the separation of the matte and slag.** With flash smelting technology; prior roasting of the ore concentrate is not required. In the flash furnace the feed material is smelted by burning the sulphur and iron content of the ore. Commercial oxygen or preheated air is injected into the furnace to stimulate combustion. Consumption of fossil fuel energy in this process is not great as smelting temperatures are sustained through the combustion of the feed material.

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* *Falconbridge Nickel Mines Ltd. is installing a fluidized bed roaster as part of a modernization program currently underway at the company's smelter in the Sudbury area.*

** *Blast furnaces at the Falconbridge smelter are being replaced with electric furnaces.*

In the converting stage of the smelting process air is blown through the molten matte. Oxygen in the air combines with iron and sulphur in the matte to form iron oxide which, when combined with silica, forms an iron silicate slag and sulphur dioxide gas which is drawn off. At the end of this stage of processing copper is approximately 98 percent pure; nickel undergoes some additional processing to increase its purity to about 95 percent.

ii) Zinc

The first stage of the zinc smelting process involves treating the metal concentrate in a roaster. The zinc calcine then goes through a leaching process where it is dissolved in hot acid to remove zinc oxides and ferrites. Natural gas and other fossil fuels are used for heating both the ore and the leaching solution.

iii) Aluminum

In Quebec, aluminum production is the dominant activity in the smelting and refining industry. The technology used to produce aluminum, the Hall-Heroult process, remains virtually unchanged since its development in the 1880's. In the manufacture of aluminum, bauxite (a hydrous aluminum oxide) is converted into an intermediate product, alumina (aluminum oxide), which is in turn reduced to aluminum metal in an electrolytic cell. Generally speaking, four to six tons of bauxite are needed to make two tons of alumina, which yields one ton of aluminum metal. From the standpoint of fossil fuel consumption, the conversion of bauxite to alumina is the most important aspect of the aluminum production process. In approximate terms, 9×10^6 Btu of fossil fuel energy is needed to produce one ton of alumina.

b) Refining

i) Nickel, Copper and Zinc

The processes used to refine nickel, copper and zinc are largely electrolytic. With respect to nickel and copper, melted matte is cast into anodes and placed in an electrolytic solution. An electric current is passed between the anode and a refined cathode thus dissolving the anode in the electrolyte; impurities remain in the electrolyte and the dissolved metal is deposited on the cathode. Inco has developed a unique process for producing nickel metal at its Sudbury refinery. The technology employs a top blown rotary converter and Inco's pressure carbonyl process. Instead of blowing air through the molten matte in the converting phase of smelting, as described above, oxygen is used; this converts the nickel matte to metal.*

Production of refined zinc involves pumping the dissolved zinc-acid solution into electrolytic cells. Through the process of electrolysis the zinc metal is deposited on cathodes.

ii) Aluminum

Conversion of alumina to aluminum is very energy intensive; roughly 15,000 kwh of electric energy is needed to produce one ton of aluminum. Reduction of alumina takes place in carbon-lined pots filled with molten cyrolite in which alumina is dissolved. A direct current is passed through the solution, causing the aluminum to be deposited as a metal at the bottom of the pot which serves as the cathode, while oxygen combines with the carbon anodes and is released as carbon dioxide gas.**

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* *J. Dasher, "The Energy Picture in Nickel Production," Mining Magazine, Volume 134, Number 5, May 1976.*

** *J.F. McDivitt and G. Manners, Minerals and Men, Baltimore, John Hopkins University Press, 1974.*

7.2 Energy Use Factors

Many factors will have an impact on future aggregate energy demand and the use of specific fossil fuels. These include:

i) the energy requirements of new process technology installed to meet expected commodity demand growth;

ii) the extent of interfuel substitutability;

iii) the introduction of energy management or conservation initiatives.

a) Nickel, Copper, Zinc

i) Process technology

To separate non-ferrous metals for energy analysis is difficult because metals occur mineralogically in the same ore and are mined, processed and smelted together. In a study prepared by EMR, estimates were made of the fossil fuel consumed in smelting and refining nickel, copper and zinc. The EMR figures are for Canada as a whole as shown in Table 73 below:

TABLE 73: FOSSIL FUEL CONSUMPTION IN SMELTING AND REFINING NON-FERROUS METALS

Metal	Fossil Fuel Use per Ton of Output[1] (Btu)
Nickel	33,340,000
Copper	31,690,000
Zinc	2,820,000

(1) Based on reported energy use in 1973.

SOURCE: Energy, Mines and Resources Canada, Present and Projected Energy Consumption in the Mineral Industry of Canada, Mineral Bulletin MR 164, Mineral Policy Series, 1976.

The EMR energy use figures clearly show that consumption of fossil fuels is much greater in smelting and refining nickel and copper as compared with zinc. Traditionally, energy intensive processes based on the use of blast or reverberatory furnaces have been used for extracting copper and nickel from concentrates. However, with the advent of much higher energy prices it is doubtful that these energy inefficient technologies will be installed in new smelters. In fact, over the forecast period blast and reverberatory furnaces in existing smelters will likely be replaced by electric furnaces or flash and continuous smelting processes.* The energy use implications of this trend will be important, because these newer technologies are generally much more energy efficient. This is clearly evident from the figures in Table 74 , which show the relative energy efficiency of traditional and new smelting processes. While these new techniques are much less energy intensive as far as fossil fuel use is concerned, even further energy economy can be achieved by using oxygen-enriched air in the smelting process. The use of oxygen is becoming more common in pyrometallurgical processes, particularly those involving flash and continuous smelting technologies. For instance, the new copper smelter under construction at Timmins will employ the Mitsubishi process with oxygen enrichment.

ii) Interfuel substitution

The scope for short-run interfuel substitution in this sector is limited. Most processes are designed to use a single fuel and conversion to substitute fuels would entail either capital

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* *W.G. Davenport and A.K. Biswas, Extractive Metallurgy of Copper, 1976.*

TABLE 74: ENERGY CONSUMPTION BY ALTERNATIVE SMELTING PROCESSES

Process	Fossil Fuel Use 10^6Btu's/ton of Metal
Blast furnace	30.6 - 61.2(1)
Reverberatory furnace	39.0 - 47.0(2)
Electric furnace	3.6(3)
Flash smelting (Outokumpu process)	22.3(4)
Continous smelting (Mitsubishi process)	
- with oxygen	8.8
- without oxygen	15.1
Noranda process	
- with oxygen	2.5
- without oxygen	19.2

(1) Assumes the use of coke as a fuel.

(2) Some unknown but minor amount of electric energy is included.

(3) Fossil fuel use for roasting.

(4) A figure for fuel use with oxygen enrichment was not available.

SOURCE: V. Dasher, op. cit.
I. Herbert, "Extractive Metallurgy," Mining Annual Review, June 1977.
Noranda Mines Ltd., Noranda Reactor, 1974.

outlays or process efficiency penalties. For example, boiler firing is one area where gas, fuel oil or coal could be used. However, plants could not readily convert from gas or oil to coal without installing new boilers or by making major modifications to existing equipment. In particular aspects of smelting and refining fuel substitution is possible. Both coal and heavy fuel oil have been used to fire the reverberatory furnaces at Inco's Sudbury smelter. Gas could be used in this process, but smelting efficiency would be adversely affected. Electric energy use in metal refining is essentially non-substitutable by fossil fuels.

Over the longer term, choice of smelter fuel is completely open through the choice of alternative technologies.

iii) Energy conservation

Rising energy prices have induced firms in this industry to actively pursue methods of reducing per unit energy use. Initial improvements have resulted from implementation of very basic housekeeping measures and recovery of waste heat. In this study, it is forecast that these initiatives will result in a 10 percent decline in fossil fuel consumption per unit of output by 1980, using 1975 as a base year for calculation purposes.

Beyond 1980, introduction of more energy efficient smelting and refining processes will lead to further reduction in per unit energy consumption. As shown by the figures in Table 74, the energy required to produce a ton of metal could decline considerably with introduction of new process technology. However, because of the difficulty in forecasting the type and timing of new capacity, it is impossible to quantify precisely the extent of additional energy use reductions. Consequently, it is arbitrarily assumed that energy use efficiency will improve by 10 percent per unit of output between 1980 and 1990 and by a further 20 percent after 1990, again using 1975 as a base year.

b) Aluminum

Reference was made earlier to the fact that aluminum production is a very energy intensive activity. It is estimated that 8.8 kwh of electric energy is required to produce one pound of primary aluminum; in some new plants this requirement is in the order of 7.8 kwh per pound.* A new smelting process is currently being developed in the United States by Alcoa. The process which is based on the electrolysis of aluminum chloride requires about 5 kwh per pound of product - an energy saving of 30-40 percent as compared with conventional technology.*

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* *Energy Mines and Resources Canada, Present and Projected Energy Consumption in the Mineral Industry of Canada, Mineral Bulletin MR 164, Mineral Policy Series, 1976.*

Most of the electric energy required by aluminum producers in British Columbia and Quebec is self generated. Self generation of thermal electric energy is negligible and is not expected to be important in the future.

The most important application of fossil fuel in aluminum production is associated with the caustic digestion of bauxite and calcining of alumina. Estimates of the energy required to produce one pound of alumina range from 4,400 to 4,839 Btu's per pound**; during the base year (1975), Alcan's alumina refinery in Arvida produced an estimated 1.1 million tons of product and consumed nearly 10 trillion Btu's of fossil fuel energy - largely heavy fuel oil. The other important use of fossil fuel is in anode baking. The Conference Board report on the U.S. aluminum industry noted that gas is preferred over fuel oil in this application. However, as most of the industry in Quebec is beyond the reach of gas service, anode baking must be done using oil. Fuel use requirements for anode baking plus other ancillary uses in aluminum production total roughly 3,000 Btu's per pound of metal output.

A brief review of the literature revealed no impending technological breakthroughs which could appreciably reduce per unit fossil fuel use in either alumina refining or anode baking. Fuel use savings per unit of output will be forecast at 10%

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* *Mining Annual Review, Mining Journal, 1977.*

** *Energy, Mines and Resources, op, cit.; The Conference Board, Energy Consumption in Manufacturing, 1974.*

by the year 2000.

The necessary price advantage of coal over oil or gas to make its use desireable in the alumina manufacturing and anode baking processes is estimated at $1.00/MMBtu.

7.3 Industry Structure and Forecast Energy Use

The primary centres of smelting activity in Canada are the following:

British Columbia
  Trail - Lead, Zinc
  Highland Valley - Copper

Manitoba
  Flin Flon - Copper, Zinc
  Thompson - Nickel

Ontario
  Sudbury - Nickel, Copper
  Timmins - Zinc, Copper

Quebec
  Noranda - Copper
  Murdochville - Copper
  Arvida - Aluminum

New Brunswick
  Belledune - Lead.

The present status and future growth prospects of the above smelter centres are discussed by province below in section 7.3 b. First however production forecasts for the major metal commodities produced in Canada are presented in section 7.3a following.

a) Metal Production Forecasts

i) Nickel, Copper, Zinc

Recent forecasts of growth in Canadian metal production are considerably less optimistic than those prepared just a few years ago. Canadian metal producers have been adversely affected by the world economic recession and the development of mining, smelting and refining capacity in third world countries. These events have had a particularly important impact on Ontario nickel producers, such as Inco and Falconbridge.

A series of studies recently completed by Energy, Mines and Resources Canada include projections of future changes in Canadian mineral production. The EMR forecasts are used in this study as a basis of projecting growth in nickel, copper and zinc production. Minor modifications have been made in assumed commodity growth rates to reflect actual changes in production which occurred between the 1975 base year and 1978 and also to take account of the near-term outlook for metal production.

Growth rates used to forecast nickel, copper and zinc production are shown in Table 75.

TABLE 75: CANADIAN GROWTH RATES OF METAL PRODUCTION

Period	AVERAGE ANNUAL GROWTH (percent)$^{(1)}$ Nickel	Copper	Zinc
1975-1980	3.45 (1.5)	4.15	7.09 (1.8)
1980-1985	1.34	3.24	5.92 } (4.0)
1985-1990	1.86		6.58 }
1990-2000	1.38	3.11	3.15
1975-2000	1.9 (1.5)	3.4	5.2 (2.5)

(1) Bracketed figures are modified growth rates, unbracketed figures are EMR growth rates.

SOURCE: Energy, Mines and Resources Canada, Nickel, Mineral Bulletin MR 157, Mineral Policy Series, 1976. Energy Mines and Resources Canada, Copper, Mineral Bulletin MR 149, Mineral Policy Series, 1976. Energy Mines and Resources Canada, Zinc, Mineral Bulletin MR 159, Mineral Policy Series, 1976.

Long-term growth in nickel production is expected to be 1.5 percent per annum as compared with an historical rate of 1.8 percent. The EMR growth estimate of 3.45 percent per year for the 1975-1980 period was sharply reduced to 1.5 percent to reflect the significant production cutbacks over this period by major producers. Even the fairly modest increase in output forecast in this study may be overly optimistic. World mineral demand is expected to weaken in the future as slower economic expansion is likely in major industrialized nations.* Also important from the standpoint of Canadian producers is the development of nickel smelter/refinery complexes in Latin American, Indonesia and elsewhere. Production from these plants will compete with Canadian production in important export markets. Further reductions in the share of world nickel market captured by Canada are likely; over the past 25 years Canada's share of the nickel market has fallen from 80 to 32 percent.**

The prospects for increased copper production are generally more promising. The forecast growth rate of 3.4 percent per annum compares with projected growth in world copper demand of 3.3 to 4.0 percent.*** Ontario production of smelted and refined copper is expected to receive an important boost in the short term with the start-up of the new Texasgulf 120,000 ton per year copper smelter/refinery complex at Kidd Creek.****

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* *Energy, Mines and Resources Canada, Mineral Industry Trends and Economic Opportunities, Mineral Bulletin MR 158, Mineral Policy Series, 1976.*

** *M.J. Gauvin, "Nickel," Canadian Minerals Yearbook, Mineral Development Sector, Energy, Mines and Resources Canada, 1976.*

*** *"Three Roads for Copper," Mining Journal, Volume 289, Number 7418, October 21, 1977.*

**** *W.G. Jeffery, Mining Annual Review, Mining Journal, June 1977.*

For purposes of this study, some important modifications were made to the rate of growth in zinc output projected by EMR. Forecast annual growth of seven percent per annum between 1975 and 1980 was reduced to 1.8 percent, the annual growth in provincial zinc production since 1967. This much lower growth rate is considered to be more realistic in light of the prevailing zinc over-supply situation. The EMR forecast of 6.3 percent growth from 1980 to 1990 was reduced to four percent to reflect the view that world demand for minerals is not expected to increase at higher historical rates. Future growth in Canadian zinc production will be importantly affected by the introduction of quotas on imports to the United States. American producers recently petitioned the U.S. International Trade Commission to restrict imports to protect domestic producers.* Export sales to the U.S. have been historically important to Canadian producers.

While this analysis does not include a forecast of other non-ferrous metal production, the energy demand forecasts which follow take into account the energy requirements related to the processing of these secondary metals.

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* *"Zinc Suffers Too,"* *Mining Journal, Vol. 290, No. 7443, April 14, 1978.*

ii) Aluminum

Primary aluminum production is forecast on the basis of planned industry expansion of productive capacity. The Aluminum Company of Canada is planning an increase in primary aluminum capacity of 300,000 tons per year by the end of the century in Quebec; this additional capacity is to be largely concentrated in the Saguenay Valley.* Assuming aluminum capacity increases to 1.2 million tons per annum from 900,000 tons at present, and that the industry operates at a 90 percent capacity factor over the forecast period, then aluminum output is projected to increase to 1.09 million tons by the year 2000. This is equivalent to an average annual growth rate of 1.4 percent which is somewhat less than the historical growth rate, but greater than the one percent per annum increase in aluminum output forecast by EMR.**

Output in British Columbia will be estimated to increase at an average rate of 1.0% per year as per the EMR forecast though no plans are presently in evidence that capacity increases at Kitimat are being contemplated.

b) Forecast Provincial Smelting Activity and Energy Use

i) British Columbia

The lead/zinc smelter of Cominco at Trail is the major facility in British Columbia; it uses no thermal coal but some metallurgical coal is used which is supplied by Kaiser Resources. Alcan has a major aluminum refinery at Kitimat but imports alumina directly so fossil fuel requirements are small. Electric energy used in these operations is supplied by company owned hydroelectric facilities. It is unlikely that increased electric energy requirements would be met with coal-fired facilities.

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* *Y. Jauron et al, Filières de production et développement régional, Office de planification et de développement due Québec, 1977.*

** *Energy, Mines and Resources Canada, Present and Projected Energy Consumption in the Mineral Industry of Canada, Mineral Bulletin MR 164, Mineral Policy Series, 1976.*

The Afton copper mine and smelter (Teck Corporation) near Kamloops will go into production in 1978; natural gas will be used at a rate of 150,000 Mcf/annum (7,500 tons coal equivalent*) to satisfy the plant's small fossil fuel requirement. An additional copper smelter is forecast for the Highland Valley, between Merritt and Kamloops; this smelter would likely handle 1,400 tons per day of copper concentrate; such a smelter would require approximately 600×10^9 Btu's/annum of fossil fuel energy (30,000 tons of coal equivalent) for an electric furnace process, or a higher requirement of $1,450 \times 10^9$ Btu's/annum (70,000 tons of coal equivalent) if a flash smelting process with oxygen were used.

Cominco's lead/zinc smelter at Trail consumes approximately 1.7 Bcf/year of natural gas (85,000 tons coal equivalent) for smelter purposes.** Output of the smelter will be forecast to increase at an average rate of 2.5% per year over the period to

* *At a coal heating value of 20 million Btu/short ton.*

** *Another 2.0 Bcf is used as a feedstock in the manufacture of ammonia.*

2000 in line with the forecast of zinc output in Table 75 above. Fossil fuel use is forecast to increase at less than half this rate to 2.9 Bcf equivalent in 2000 on the assumption that all new or replacement smelting processes will be more energy efficient than current practice.

Forecast Energy Use

Coal could be utilized in a Highland Valley copper smelter as discussed above; it will be assumed such a smelter will be operational in 1985 with a potential annual coal demand of 1450 x 10^9 Btu.

Coal is a potentially substitutable energy source in the lead/zinc smelter at Trail. The potential coal demand is forecast at 50% of total fossil fuel demand on the assumption that many of the smelter uses of natural gas are too small to convert to coal.

Potential coal demand in British Columbia is thus forecast as follows:

	Fossil Fuel Demand			
	Trail		Highland Valley	
	Without Conservation	With Conservation		Potential Coal Demand
		10^9 Btu		10^9 Btu
1978	1700	1700	-	850
1980	1785	1785	-	890
1985	2020 (.95)*	1920	1450	2410
1990	2286 (.90)	2060	1450	2480
1995	2586 (.80)	2070	1450	2485
2000	2925 (.70)	2050	1450	2475

* *Conservation factors.*

A coal discount factor of $0.75 MMBtu over the prevailing gas price is assumed adequate to make it competitive at Highland Valley; at Trail an average discount of $1.25/MMBtu, considering both existing and new plant, is assumed necessary to make coal economically competitive.

ii) Manitoba

Two major smelter operations are located in northern Manitoba: Hudson Bay Mining and Smelting has a copper-zinc smelter at Flin Flon and Inco operates a nickel smelter at Thompson.

In 1977 Hudson Bay Mining and Smelting consumed 115,000 short tons of coal from Byron Creek Collieries in its copper ore smelting process and 59,000 tons in the zinc forming plant.* The reverberatory furnace at Flin Flon was changed to an oil system from coal in 1970; consumption of coal if this furnace was operated on coal would be in the order of 60,000 tons/year.

The major portion of coal using facilities related to the reverberatory furnace are still in place; as a result a relatively small price spread (say not more than $0.50/MMBtu) between the price of coal and fuel oil would be sufficient to maintain coal in its present uses and cause it to be reintroduced in the reverberatory furnace. Copper/zinc output in the Flin Flon area will be assumed to increase at an average rate of 3% per year over the 1978-2000 period to some 1.9 times current levels.

The potential for coal consumption in the Flin Flon area is forecast to increase from a present level of 235,000 to 315,000 short tons in 2000 as follows:

	Potential Coal Consumption short tons		
	without conservation		with conservation
1978	235,000		235,000
1980	250,000		250,000
1985	290,000	(0.95)*	275,000
1990	335,000	(0.90)	300,000
1995	390,000	(0.80)	310,000
2000	450,000	(0.70)	315,000

* *Energy conservation factors.*

Inco's Thompson smelting operation has an annual capacity of 1,400,000 of concentrates; it employs a fluid bed roasting process and electric furnace smelting. Fossil fuel use is considered to be too small to justify conversion to coal, because of relatively small quantities involved and the consequent very high transportation charges.

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* *Discussion with HBM&S personnel.*

iii) Ontario

Metal smelting and refining capacity is to a large extent dominated by two major companies, Inco and Falconbridge. These two firms have extensive processing facilities designed to treat copper and nickel ores mined in the Sudbury Basin. Other metallurgical works of significance include: the zinc smelter/refinery complex operated by Texasgulf at Timmins; the Chromasco plant at Haley producing magnesium and strontium metal; and the Eldorado Nuclear uranium processing facility at Port Hope.

Production of copper, nickel and zinc was approximately 84 percent of the value of total non-ferrous metal production in Ontario in 1975.* Over the historical period from 1964 to 1977 there was considerable variation in the rate of growth of production for each of these metals; growth rates varied between 1.8 percent per annum for nickel to 12.2 percent for zinc. It is noteworthy that physical production of all three actually declined between 1974 and 1977; for example, zinc production in 1977 was roughly 67 percent of the 1974 level. The weakening of export markets stemming from the worldwide recession of recent years has had an important impact on Ontario metal producers. While nickel and copper have recovered slightly in the past two years, the decline in zinc production has not yet been reversed largely on account of a chronic over-supply situation throughout the world.*

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* *Statistics Canada, General Review of the Mineral Industries, 1975.*

Growth rates used to forecast copper, zinc and nickel production in Ontario are the same as those developed in Table 75 above. Ontario's projected metal production using these growth rates is shown in Table 76 below.

TABLE 76: PROJECTED METAL PRODUCTION, ONTARIO, 1975-2000

Year	METAL PRODUCTION (tons) Nickel	Copper	Zinc
1975 (actual)	197,418	284,152	370,214
1976 (actual)	206,613	286,819	349,646
1977 (actual)	203,946	308,169	321,790
1980	213,260	348,150	339,480
1985	227,940	408,325	413,030
1990	249,940	478,900	502,510
1995	267,670	558,150	586,800
2000	286,650	650,510	685,230

Ontario Energy Use

Fossil fuel demand associated with the production of nickel, copper, zinc and other non-ferrous metals was estimated for the base year (1975) by first multiplying nickel, copper and zinc production in the base year by the fuel use factors in Table 73. Fuel consumption in other non-ferrous metal production is a residual derived by subtracting the fuel use related to nickel, copper and zinc production from total fuel consumption. Base year fossil fuel demand is shown below:

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* *Mining Journal, "Zinc Suffers Too," Volume 290, No. 7443, April 14, 1978.*

Metal	Fossil Fuel Consumption (1975) (10^9 Btu's)
Nickel	6,581
Copper	9,004
Zinc	1,044
Other	5,498
Total	22,127*

Total fossil fuel use (without conservation initiatives) was forecast by multiplying projected metal production in Table 76 by the fuel use factors in Table 73; this forecast is shown in Table 77. It was assumed that fuel use for other metal production is a constant proportion (33 percent) of total fuel consumed in nickel, copper and zinc production. Estimated total fossil fuel demand was modified by applying the energy conservation assumptions described earlier. While non-ferrous mineral output is expected to nearly double over the forecast period, fossil fuel energy use is forecast to increase by only 16 percent.

Applications in which coal could technologically substitute for oil or natural gas will be assumed at 50% of total fossil fuel demand.

Potential coal demand will thus remain reasonably steady in the range of 11 to 13 x 10^{12} Btu/yr. over the forecast period. One half of this amount will be assumed accessible at a coal price discount of $0.75/MMBtu in new installations and one half would have to be discounted at $1.25/MMBtu to be competitive in conversions to existing plants.

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* *Total fuel consumption from Statistics Canada, Consumption of Purchased Fuel and Electricity, 1975, 1978.*

TABLE 77: PROJECTED FOSSIL FUEL DEMAND, ONTARIO SMELTING AND REFINING INDUSTRY, 1975-2000

	FOSSIL FUEL DEMAND (10^9 Btu's)						
Year	Nickel	Copper	Zinc	Other	Total without Conservation	Total with Conservation	Potential Coal Demand
1975 (actual)	6,581	9,004	1,044	5,498	22,127	22,127	11,060
1980	7,110	11,030	960	6,360	25,400	22,914	11,450
1985	7,600	12,940	1,160	7,230	28,930	24,591	12,300
1990	8,330	15,180	1,420	8,300	33,230	26,584	13,300
1995	8,920	17,690	1,650	9,410	37,670	26,369	13,200
2000	9,560	20,610	1,930	10,690	42,790	25,674	12,800

iv) Quebec

In dollar value terms, aluminum, copper and zinc production represented 65 percent of the value of all metal production in the province during 1975. Time series data showing historical production of these three commodities are presented in Table 78. While growth in aluminum output averaged 1.7 percent per year between 1964 and 1977, production of copper and zinc declined in absolute terms over this period. Mine closures precipitated by the exhaustion of ore reserves, low metal prices and rapidly escalating operating costs have importantly contributed to declining production.*

Copper and zinc metal produced in smelters and refineries far exceeds the metal content of ores mined in Quebec. In fact, roughly 55 percent of the copper concentrates feeding the smelters at Rouyn-Noranda and Murdochville come from mines outside of Quebec.** Similarly, the copper refinery in Montreal-East, as well as treating blister copper from Quebec smelters, also processes metal from extra-provincial sources. The table below compares Quebec mine, smelter and refinery production of copper:

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* *Between 1975 and 1977, seven mines producing copper concentrate were closed.*

** *Ministère des Richesses Naturelles, l'industrie Minière due Québec, 1977.*

	1974	1975 (,000 tons)	1976
mine production	159	130	124
blister copper	338	304	302
refined copper(1)	427	399	386

(1) Includes copper produced from scrap.

SOURCE: Ministère des Richesses Naturelles, l'Industrie Minière du Québec, 1977.

TABLE 78: PRODUCTION OF ALUMINUM, COPPER AND ZINC, QUEBEC, 1964-1977

Year	METAL PRODUCTION (tons) Aluminum	Copper	Zinc
1964	637,910	158,088	236,540
1965	647,020	173,938	272,883
1966	664,680	171,998	293,147
1967	755,760	166,385	245,883
1968	708,550	167,601	213,153
1969	848,890	160,068	198,531
1970	815,500	172,642	205,030
1971	830,830	184,823	174,419
1972	751,660	176,432	163,244
1973	770,770	157,841	155,259
1974	836,290	158,991	138,282
1975	718,900	129,583	138,055
1976	460,000(1)	124,266	129,817
1977	796,000(2)	118,704	118,617
	Average Annual Growth (percent per annum)		
1964-1969	5.9	0.3	-3.6
1969-1974	-0.3	- 0.1	-7.5
1974-1977	-1.7	-10.2	-5.3
1964-1977	1.7	- 2.2	-5.5

(1) Labour disputes at Alcan's Quebec smelters disrupted production.

(2) Estimated on the basis of information provided by Minerals Branch of EMR and Aluminum Co. of Canada Ltd.

SOURCE: Statistics Canada, General Review of the Mineral Industries, 1964-1975 and Statistics Canada, Canada's Mineral Production, Preliminary Estimate, 1976-1977 (copper and zinc production figures).

Ministère de l'Industrie et du Commerce, l'Industrie de l'Aluminium au Québec, 1976; The Financial Post Corporation Service; Mining Journal, Mining Annual Review, 1977 (aluminum production).

Zinc metal production at the Canadian Electrolytic Zinc refinery in Valleyfield is greater than the zinc content of concentrates from Quebec sources. During 1976, production of refined zinc totalled 140,000 tons as compared with Quebec mine production of zinc which was 130,000 tons. Exports of zinc concentrate from the province have averaged 40 percent of production in recent years; these exports have been largely offset by imports from Ontario and elsewhere.

Forecasts of market growth focus on three principal metal commodities - aluminum, copper and zinc. For forecasting purposes output of copper and zinc is projected on the basis of the Canadian growth rates developed in Table 75. Aluminum capacity, as discussed above in 7.3.a is forecast to increase from some 900,000 tons per year presently to 1,200,000 tons per year in 2000.

Quebec Energy Use

The methodology used to forecast aggregate fossil fuel demand is, with some minor modifications, the same as used in the Ontario analysis. Metal production for aluminum, copper and zinc are shown in Table 79.

TABLE 79: PROJECTED METAL PRODUCTION, QUEBEC, 1975-2000

	METAL PRODUCTION (tons)		
Year	Aluminum	Copper(1)	Zinc(2)
1975 (actual)	718,900	304,000	117,700
1976 (actual)	460,000	302,000	140,000
1977 (estimated)	796,000	N/A	N/A
1980	829,000	355,000	148,000
1985	888,000	416,000	180,000
1990	951,000	488,000	219,000
1995	1,019,000	569,000	256,000
2000	1,080,000	663,000	299,000

(1) Production from 1980 onwards assumed at 90% of forecast capacity.

(2) Production of blister copper by Quebec smelters.

(3) Production of zinc by Quebec refineries.

Fossil fuel consumption by metal commodity was estimated for the base year (1975) by multiplying metal production times average fossil fuel use per unit of output. Fuel use related to production of other non-ferrous metals was calculated as a residual by subtracting aluminum, copper and zinc fuel requirements from total usage. Base year fossil fuel consumption is estimated below:

Metal	*Fossil Fuel Consumption (1975)* *(10^9 Btu's)*
Aluminum	14,140
Copper	9,634
Zinc	501
Other	798
Total	25,073*

* *Total fuel consumption from Statistics Canada, Consumption of Purchased Fuel and Electricity 1975, 1978.*

Forecasts of copper and zinc fossil fuel requirements were derived by multiplying projected commodity production by estimated fossil fuel use per unit of output. These figures were adjusted to take account of the effects of expected improvements in fuel use efficiency; the assumptions used are the same as those in the Ontario analysis namely reductions in per unit energy use from the 1975 base of 10% by 1980, 20% by 1990, and 40% by 2000.

A two step process was employed to forecast fossil fuel demand for aluminum:

(i) A forecast of alumina production was prepared and multiplied by average per unit fuel consumption (4400 Btu per pound of alumina).

(ii) Projected fossil fuel use in other aspects of aluminum production was derived by multiplying forecast aluminum production by an estimate of fuel consumption in process applications other than alumina production (3000 Btu per pound of aluminum).

A 10% reduction in fossil fuel energy use per unit of consumption is assumed by the year 2000.

Projected fossil fuel requirements by metal commodity are summarized in Table 80.

The necessary price advantage to make coal attractive in the production of alumina is estimated at $1.00/MMBtu relative to prevailing delivered oil or gas prices. Concerning the smelting of other non-ferrous metals it is assumed one half of the coal potential could be realized at a coal discount to oil or gas of $0.75/MMBtu (new installations) and one half would have to be discounted at $1.25/MMBtu (conversions to existing plants).

TABLE 80: PROJECTED FOSSIL FUEL DEMAND, QUEBEC SMELTING AND REFINING INDUSTRY, 1975-2000

Year	FOSSIL FUEL DEMAND (10^9 Btu's)						Potential Coal Demand
	Aluminum[1]	Copper[2]	Zinc[3]	Other[4]	Total without Conservation	Total[5] With Conservation	
1975 (actual)	14,140	9,634	501	798	25,073	25,073	-
1980	19,564	11,250	420	921	32,155	30,892	20,337
1985	20,956	13,180	510	1,081	35,727	32,979	21,595
1990	22,443	15,460	620	1,270	39,793	35,182	22,916
1995	24,048	18,030	720	1,481	44,279	36,375	23,740
2000	25,488	21,010	840	1,726	49,064	37,041	24,244

1 *Alumina manufacture fossil fuel use at* 17.6×10^6 *Btu/ton aluminum.*
Anode baking fossil fuel use at 6.0×10^6 *Btu/ton aluminum.*
Total fossil fuel use = 23.6×10^6 *Btu/ton aluminum.*

2 *Base year fossil fuel use =* 31.69×10^6 *Btu/ton copper.*

3 *Base year fossil fuel use =* 2.82×10^6 *Btu/ton zinc.*

4 *Other fossil fuel demand maintained at 7.9% of total copper + zinc demand.*

5 *Fossil fuel use for aluminum decreased from* 23.6×10^6 *Btu/ton aluminum in 1980 by 10% to* 21.2×10^6 *Btu/ton in 2000. Fossil fuel use for copper, zinc and other metals decreased to 90% of base year use in 1980, 85% in 1985, 80% in 1990, 70% in 1995, and 60% in 2000.*

6 *Potential coal demand calculated as 75% of forecast fossil fuel demand for aluminum and 50% of forecast demand for other metals.*

v) New Brunswick

Brunswick Mining and Smelting Corporation Ltd. operates a blast furnace lead smelter near Belledune, New Brunswick, with a capacity of 78,000 tons/year of refined lead*. Lead production has increased steadily over the past 5 years to over 56,000 tons in 1977:

Smelter output, Pb (tons)**	
1977	56,400
1976	51,400
1975	50,900
1974	44,200
1973	34,450

Bismuth, silver and copper are also produced as a by-product of the lead smelting operation. Sulphuric acid produced as a by-product in the lead smelting operation is used in the fertilizer plant to produce diammonium phosphate; in 1977 approximately 100,000 tons of this fertilizer was produced.

At the current level of operation the smelter consumes approximately 65,000 bbls. of heavy fuel oil annually***, equivalent to some 7.5×10^6 Btu/ton refined lead. This fuel oil consumption is equal to approximately 20,000 tons of coal per annum. Less than ¼ of the oil is used for steam raising the remainder being utilized in a variety of uses such as in heating the lead kettles, in the sulphuric acid plant, in the sinter plant as a starter, in the copper reverberatory furnaces, etc. A maximum of 50% of the fossil fuel energy use is assumed to be substitutable by coal; the remaining energy requirements are too small and disperse to enable coal to be used. It will further be assumed that an average coal price discount to fuel oil of $1.50/MMBtu will be necessary to make coal competitive. This is higher than the figure used for the Trail smelter because of the smaller scale of operation involved.

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* *EMR, Operators List No. 3, January 1977.*

** *Noranda Mines Ltd., Annual Report 1977, p. 14.*

*** *Telephone communication with Brunswick Mining and smelting personnel.*

Forecast Energy Use

Proved and probable reserves of lead/zinc ore at the No. 12 mine supplying the smelter are over 100,000,000 tons; ore mined in 1977 was approximately 3,500,000 tons with a Pb/Zn grade of 12.9%. Brunswick smelter treats ore from the No. 6 and No. 12 mines as well as some purchased concentrates. A new shaft is being opened at No. 12 mine to increase mining capacity from 9,400 to 11,000 tons per day. A 30 year mine life can be foreseen at current mining levels based on proved and probable reserves.

New Brunswick smelter output will be assumed to grow at an average rate of 2% per year reaching 85,000 tons refined lead/year in 2000. Per unit fossil fuel energy use will be forecast to decline to 70% of 1978 levels by 2000. Potential coal demand is thus forecast as follows:

	Lead Output	Fossil Fuel Demand		Potential** Coal Demand
		Without Conservation	With* Conservation	
	(10^3 tons)		(10^9 Btu)	
1977	56	420	420	210
1980	60	450	450	225
1985	65	490	465	230
1990	70	525	470	235
1995	77	575	460	230
2000	85	640	450	225

* *Energy conservation factors 1985 = 0.95; 1990 = 0.90; 1995 = 0.80; 2000 = 0.70.*

** *50% of fossil fuel demand assumed as not amenable to coal substitution.*

8.0 POTASH

8.1 Industry Structure and Output

Canada is the second largest producer of potash in the world after Russia (Table 81). To date all of Canada's production has originated in Saskatchewan. Two mines are planned for New Brunswick and are forecast here to come on stream beginning in 1981; International Minerals and Chemicals (IMC) intends to construct a 1,000,000 ton (KCl) plant at Salt Springs, and the Potash Company of America plans a similar sized facility at Sussex.

The raw ore from which potash, or potassium chloride (KCl), is derived is comprised of approximately 50% sodium chloride (NaCl), 45% potassium chloride (KCl), and 5% clay. The potash beds may be as much as 25 feet thick. Potash (KCl) is used principally as a fertilizer in combination with nitrogen and phosphates. Over 95% of the world's production of potash is used in fertilizer.

It is common to express potash, or muriate of potash, that is shipped from the mines as KCl (potassium chloride). In the fertilizer industry potash is graded on the basis of its potassium oxide (K_2O) equivalent. A K_2O rating represents approximately 60% of the actual weight of the KCl product tons; therefore, a production of one million tons KCl is equivalent to 600,000 tons K_2O,

Saskatchewan's production of potash has been in the order of 4 to 6 million short tons (K_2O) for the past several years (Table 82).

Output in Saskatchewan is forecast to increase from 6.2 million short tons (K_2O) in 1978 to 10.5 million tons in 1985 and 16.4 million tons in 2000 (Table 83). In New Brunswick production is estimated to reach 1.9 million tons by 2000.

8.2 Energy Use

All but one mine in Saskatchewan recovers the potash ore by underground mining procedures, hoisting a solid ore to the surface for processing. Kalium Chemicals operates a solution mine at Belle Plaine, west of Regina, whereby heated water is pumped into the ore zone from the surface and the potash is recovered through wells in solution. The solution mining process is much more energy intensive than recovery by mining methods and the assumption in this analysis is that all future capacity will be of the mining type.

Fossil fuel energy in mining operations is used for two primary purposes in the potash refining process. About 2/3 of the total is used to raise steam for the liquefaction of fines and subsequent recrystallization under vacuum. The other 1/3 is used for drying: the KCl in the coarse material is

TABLE 81: WORLD POTASH PRODUCTION, CALENDAR YEARS, 1973 TO 1977
(thousands of short tons, K_2O)

	1973	1974	1975	1976	1977
Canada	4,716	6,041	5,992	5,497	6,704
United States	2,634	2,564	2,529	2,432	2,459
U.S.S.R.	6,522	7,260	8,757	9,160	9,590
East Germany	2,817	3,157	3,328	3,484	3,576
West Germany	2,809	2,888	2,449	2,244	2,580
France	2,546	2,285	2,116	1,767	1,742
Israel	585	669	789	761	661
Spain	521	n.a.	506	590	621
Italy	147	n.a.	155	154	163
Congo	284	314	315	280	89
United Kingdom	--	--	17	50	89
TOTAL	23,583	25,800	26,953	26,419	28,275

SOURCE: Phosphorus and Potassium, Jan./Feb., 1978 and Jan./Feb. 1976.

TABLE 82: SASKATCHEWAN POTASH PRODUCTION AND SHIPMENTS, 1972-1978

	Production	Shipments thousands of short tons K_2O	Difference*
1972	4,329	3,852	477
1973	4,684	4,909	(225)
1974	6,058	6,367	(309)
1975	5,920	5,152	768
1976	5,515	5,749	(234)
1977	6,675	6,354	321
1978**	6,200	-	-

* *Calendar year data on potash production (from the Saskatchewan Department of Mineral Resources) and shipments (from Statistics Canada).*

** *Information from Potash Corporation of Saskatchewan.*

SOURCE: Saskatchewan Power Corporation, Forecast Electricity and Natural Gas 1978-1988, Sept. 1978. p-52.

TABLE 83: FORECAST POTASH PRODUCTION, CANADA, 1978-2000
(million short tons K_2O)

	Saskatchewan*	New Brunswick**	Total
1978	6.2		6.2
1981	8.2	0.6	8.8
1985	10.5	1.2	11.7
1990	12.2	1.4	13.6
1995	14.1	1.6	15.7
2000	16.4	1.9	18.3

* *Saskatchewan output figures to 1985 from Potash Corporation of Saskatchewan estimates. From 1985 to 2000 output increased at an average annual rate of 3% per year.*

** *Two currently planned plants of IMC and Potash Corporation of America estimated to be in production by 1982. From 1985 to 2000 output is forecast to increase by 3% per year.*

separated from the ore by a flotation process; both the recrystallized fines and the material from the flotation cells are centrifuged and dried in natural gas open fired kilns. Virtually all the fossil fuel used by the potash industry in Saskatchewan is natural gas.

Excluding the Kalium mine use of electricity and natural gas in potash production has been as follows:

	kwh/ton K_2O	Btu x 10^6/ton K_2O
1970	199.8	2.53
1971	165.1	2.38
1972	170.6	2.26
1973	165.9	2.12
1974	154.1	1.95
1975	155.8	1.88
1976	169.5	2.03
1977	161.6	1.89

SOURCE: Saskatchewan Power Corporation, Forecast Electricity and Natural Gas 1978-1988, Sept. 1978, p. 61.

Kalium's use of natural gas is very much higher at an estimated 11 x 10^6 MMBtu/ton K_2O.

Significant economies in energy use can be predicted for potash operations. Most plants were designed in the 1960's when natural gas prices of less than $0.25/MMBtu were standard. Under current prices of over $1.50/MMBtu, and expectations of higher prices ahead, energy conservation measures at existing plants will be undertaken and new plants will be built with more energy efficient equipment. Stack gas heat recovery systems, more efficient dryers, and centrifuging material to lower moisture content prior to drying are examples of methods which will be instituted to reduce unit fossil fuel use.

One opinion from a source at the Potash Corporation of Saskatchewan was that a reduction of 1/4 to 1/3 in fossil fuel consumption per unit of output could be achieved in existing plants at a relatively low cost. The assumption in this report is that average fossil fuel use per unit of output in all mining operations will reduce from the current level of approximately 1.9 MMBtu/ton to 1.1 MMBtu/ton by 2000, or to less than 60% of present unit consumption. New Brunswick unit consumption is forecast to decrease from 1.4 MMBtu/ton in 1981 to 1.0 MMBtu/ton in 2000. The Kalium consumption is assumed to reduce to 80% of its present level in 1980 to approximately 9 MMBtu/ton and remain steady thereafter. Fossil fuel use on this basis is forecast to increase to 23,600 x 10^9 Btu in 2000 in Saskatchewan and to 1900 x 10^9 Btu in New Brunswick (Table 84).

Coal use in existing mining facilities would require the replacement of existing boilers and dryers by new coal units, plus the addition of the necessary coal handling and ash disposal equipment. A coal discount factor of $1.75/MMBtu will be assumed as necessary to make these conversions economic*; the open firing of coal in kiln drying is assumed not to be acceptable and an alternative procedure such as steam radiators with fans may be necessary. In new plant installations, a coal price discount factor of $1.25/MMBtu will be considered adequate to encourage coal use. It will be assumed that the Kalium Chemicals' plant will find coal use attractive at a discount to natural gas of $1.25/MMBtu.

Individual potash plants are usually sized in the range of 600,000 to 900,000 tons K_2O. Mining projects using 1.5 MMBtu/ton of fossil fuel would thus have a coal requirement of 45,000 to 67,000 tons per year of 10,000 Btu/lb. coal if all fossil fuel was coal. The Kalium plant would consume over 300,000 tons per year of 10,000 Btu/lb. coal if all natural gas was displaced.

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* *A 100,000 lb./hr. boiler would be adequate for a 1,000,000 ton (KCl)/yr. potash plant.*

TABLE 84: FOSSIL FUEL DEMAND IN THE POTASH INDUSTRY 1978-2000

	SASKATCHEWAN			NEW BRUNSWICK			TOTAL FOSSIL FUEL DEMAND
	Output* 10^6 s.tons K_2O	Unit Fossil** Fuel Demand Mining MMBtu/ton	Total*** Fossil Fuel Demand 10^9Btu	Output 10^6 s.tons K_2O	Unit Fossil Fuel Demand MMBtu/ton	Total Fossil Fuel Demand 10^9Btu	10^9Btu
1978	6.2	1.9	17,500				17,500
1981	8.2	1.7	19,050	0.6	1.4	840	19,890
1985	10.5	1.5	21,000	1.2	1.3	1,560	22,560
1990	12.2	1.3	21,250	1.4	1.2	1,680	22,930
1995	14.1	1.2	22,400	1.6	1.1	1,760	24,160
2000	16.4	1.1	23,600	1.9	1.0	1,900	25,500

* *Output includes an assumed constant production of 700,000 short tons K_2O from Kalium Chemicals from 1980 onwards. Output forecasts from Table 83.*

** *Unit energy consumption of mining projects only.*

*** *Includes fossil fuel use at Kalium of 9 Mcf/ton from 1980 to 2000.*

9.0 GENERAL INDUSTRIAL

Previous sections of the chapter cover a number of specific industrial activities which as major energy consumers are of particular interest as potential coal consumers. In this section consideration is given to the potential for coal consumption in the aggregate of all other industrial activity. Thus, the "general" industrial category may be defined as including all industrial activity except:

	Standard Industrial Classification*
pulp and paper mills	271
iron and steel mills	291
smelting and refining	295
cement manufacturers	352
lime manufacturers	358
petroleum and coal products**	group 18
chemical and chemical products	group 19
potash mines	0794

9.1 Historical Energy Demand

The 1975 pattern of fuel consumption in the general industrial sector is outlined on a regional basis in Table 85. Coverage is restricted to coal and the fuel types for which coal would generally be considered a potential substitute (light fuel oil,

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* *Statistics Canada, Catalogue 12-501, Standard Industrial Classification Manual.*

** *Only the oil sands and heavy oil component of this group is included in this study. The assumption is made that within the range of crude oil and natural gas prices forecast for the study, other components of the energy supply industries will not be coal consumers.*

TABLE 85: REGIONAL CONSUMPTION OF SELECTED FUELS BY THE GENERAL INDUSTRIAL SECTOR, 1975

	Coal	LFO	HFO	Gas	Total
			(10^9 Btu's)		
Atlantic (1)	-	7,907	6,669	-	14,576
Quebec	1,608	29,481	58,369	31,225	119,683
Ontario	6,442	20,281	26,503	166,436	219,662
Prairie	1,305	2,158	3,097	29,697	36,257
Alberta	96	1,310	1,326	58,840	61,572
B.C. and Territories	-	2,399	5,491	20,439	28,329
Canada	9,451	62,536	101,455	306,637	480,079
			(percent of regional total)		
Atlantic (1)	-	54.2	45.8	-	
Quebec	1.3	23.8	48.8	26.1	
Ontario	2.9	9.2	12.1	75.8	
Prairie	3.6	6.0	8.5	81.9	
Alberta	0.2	2.1	2.2	95.6	
B.C. and Territories	-	8.5	19.4	72.1	
Canada	2.0	13.0	21.1	63.9	

SOURCE: Derived from Statistics Canada, Catalogue 57-207, Detailed Energy Supply and Demand in Canada; Catalogue 57-208, Consumption of Purchased Fuel and Electricity.

NOTES: Fuel consumption data was aggregated by fuel type for each specified industry using 57-208. Totals were then deducted from total industrial fuel consumption including consumption for conversion to secondary fuel (i.e. industrial generation of electricity), but excluding consumption by the energy supply industries. The latter data is contained in 57-207. In some cases aggregation of fuel consumption data for the specified industries necessitated use of data for the industrial group rather than the specific industry. The result is a minor overstatement of the aggregate of consumption by the specified industries.

(1) Imputed values as differences between Canadian totals and aggregate of regional totals because of incomplete data resulting from secrecy requirements of the Statistics Act.

and heavy fuel oil). Motive fuels (gasoline, diesel), special heating fuels (kerosene, LPG's) and electricity are excluded. The methodology used to derive the table is outlined in its accompanying notes.

As in the case for the industrial groups considered in previous sections, the relative importance of coal as a fuel for general industrial activity has declined substantially during the past decade. Table 86 indicates the declining importance of coal between 1965 and 1975. Additional analysis of the data indicates that while the general industrial sector accounts for a growing share of total industrial fuel consumption (45 percent in 1975 versus 36 percent in 1965) the decline in coal's share is somewhat more rapid than for the aggregate of all specified industries.

9.2 Future Energy Demand

Energy requirements for general industrial activity will be dependent upon output, which is in turn dependent upon relationships between the following variables:

- population;
- participation rate (the percentage of the population of working age who are in the labour force);
- the proportion of the labour force in goods-producing industries (as opposed to service industries which would generally be clased as the "commercial" sector);
- productivity per person in the goods-producing industries.

The relationship between output and energy requirements will be dependent upon changes in energy intensiveness per unit of output. All of the above factors may be indexed relative to 1975 levels, so that future energy requirements may be forecast by multiplying the 1975 base year value for each region under consideration by the appropriate indices.

Once estimates have been made concerning the probable trends in the variables such as labor force, productivity, etc., over the forecast period, total fossil fuel consumption in the general industrial sector is forecast as follows:

Goods-producing Labour Force Index x Productivity Index = Output Index

Output Index x Index of Fossil Fuel Consumption x Fossil Fuel Consumption in Base Year = Forecast Fossil Fuel Consumption.

(a) Industrial Output

As it is necessary to have a Canada-wide analysis in this study and desirable to have provincial breakdowns to allow the desired regional aggregations, Statistics Canada data and population projections are used. In some instances alternative provincial material could be used; however it would not provide consistency between provinces, nor would it be complete for all provinces.

Base year and projected populatuion figures for persons 15 years of age and over are outlined in Table 87. The 1978 Statistics Canada "Projection 2" is used in which net in migration to the country is held at 75,000 and various assumptions are made about changes in fertility rate and migration between provinces over time.* Population levels indexed to the 1975 base year are also outlined in the table.

Historical participation rates are outlined in Table 88.** From this data it is apparent that the participation rate generally has been increasing, and that the rate of increase has been accelerating. Development of future participation rates through detailed analysis is beyond the scope of this study, and suitable projections on a regional basis are not available. As an alternative inferences are drawn from an Ontario study*** as a basis for the estimated future participation rates in Table 89. In the Ontario study participation rates for 1995 are forecast to reach 68.1 and 70.0 percent for Canada and Ontario respectively.

* *Statistics Canada, Catalogue 91-520, Population Projections For Canada and The Provinces, 1972-2002, 1978 Preliminary.*

** *See note to Table 88 concerning survey technique for participation rates.*

*** *Ontario Ministry of Treasury, Economics and Intergovernmental Affairs, Long Term Outlook for Labour Force Growth: Canada and Ontario, June 1976.*

The proportion of the labour force involved in goods-producing industries is outlined in Tables 90 and 91. Between 1951 and 1971 there was a rapid shift of the labour force from goods-producing to service industries in all regions. The more recent data (1975 to 1977) indicates that the rate of this shift is slowing. It is uncertain whether the shift from goods-producing industries will continue throughout the forecast period, or whether the proportions will stabilize. Estimates of the future splits are based on the premise of a continuing but slowing rate of decline of the share of the goods-producing sector until relative stability is reached in 1990 (Table 92).

The final factor which must be considered in order to produce a forecast of industrial output is the productivity per worker. Over the past three decades there has been a gradual reduction in the average annual increase in output per person employed in the goods-producing industries, as shown in Table 93. While the average increase of only 1.5 percent per annum for 1972 to 1977, and the actual declines in two of the years, may be regarded as a result of economic recession, and not indicative of long-term future trends, there is little doubt that productivity increases per employed person will continue to moderate. For the forecast period the following annual growth rates are used to provide indexed levels of productivity per employed person:

	percent per annum
1975-1980	3.0
1980-1985	3.5
1985-1990	3.0
1990-2000	2.5

	indexed productivity
1975	1.00
1980	1.19
1985	1.38
1990	1.60
1995	1.81
2000	2.04

TABLE 86: CONSUMPTION OF SELECTED FUELS BY THE GENERAL INDUSTRIAL SECTOR IN CANADA, 1965 TO 1975

	1965	1970	1975
		(10^9 Btu's)	
coal	35,968	15,396	6,554
fuel oil(1)	130,904	163,644	253,758
natural gas	106,908	186,813	270,442
total	273,510	365,853	530,754
		(percent of total)	
coal	13.1	4.2	1.2
fuel oil(1)	47.9	44.7	47.8
natural gas	39.1	51.1	51.0

SOURCE: Derived from Statistics Canada, Catalogue 57-207, Detailed Energy Supply and Demand in Canada; Catalogues 57-208 and 57-506, Consumption of Purchased Fuel and Electricity.

NOTES: The statistical basis varies from Table 90 as it is necessary to use industrial group data rather than data for specific industries, and also to use a broader range of fuel oil types. Neither of these factors should have a significant influence in determining the changing relative importance of coal.

(1) *Includes kerosene, diesel, light fuel oil and heavy fuel oil.*

TABLE 87: PROJECTED FUTURE POPULATION OF CANADA BY REGION (Persons 15 Years of Age and Over)

	1975	1980	1985	1990	1995	2000
				(000 persons)		
Atlantic	1,521.2	1,681.5	1,796.5	1,876.0	1,951.7	2,046.3
Quebec	4,614.9	4,450.6	5,148.6	5,283.4	5,434.6	5,622.1
Ontario	6,095.5	6,681.7	7,126.4	7,476.5	7,823.1	8,208.7
Prairie	1,418.1	1,535.1	1,613.4	1,665.3	7,721.5	1,744.7
Alberta	1,265.5	1,559.8	1,823.3	2,094.3	2,365.2	2,648.9
B.C. & Territories	1,873.9	2,080.6	2,288.9	2,509.7	2,736.1	2,979.9
				(index)		
Atlantic	1.00	1.11	1.18	1.23	1.28	1.35
Quebec	1.00	1.07	1.12	1.14	1.18	1.22
Ontario	1.00	1.10	1.17	1.23	1.28	1.35
Prairie	1.00	1.08	1.14	1.17	1.21	1.27
Alberta	1.00	1.23	1.44	1.65	1.87	2.09
B.C. & Territories	1.00	1.11	1.22	1.34	1.46	1.59

SOURCE: Statistics Canada, Catalogue 91-202, Population of Canada by Provinces and Sex and Age Group, June 1, 1975; Catalogue 91-250, Population Projections for Canada and The Provinces, 1977-2002, 1978 Preliminary.

TABLE 88: PARTICIPATION RATE IN LABOUR FORCE, 1960 TO 1975

	1960	1965	1970	1975
		(percent)		
Atlantic	47.1	48.1	47.5	51.9
Quebec	53.6	53.2	54.3	57.2
Ontario	57.0	56.7	58.0	61.3
Prairie	54.7	55.5	57.1	59.3
B.C.	51.7	53.8	57.3	60.2
Canada	54.2	54.4	55.8	58.8

SOURCE: Statistics Canada, Catalogue 71-001, The Labour Force, December 1975.

NOTE: The basis is the old labour force survey technique involving population of 14 years and over. The current survey technique, as used elsewhere in the study, involves population of 15 years and over.

TABLE 89: ESTIMATED FUTURE PARTICIPATION RATES BY REGION, 1980 TO 2000

	1975 (1)	1980	1985	1990	1995	2000
			(percent)			
Atlantic	53.4	56.4	59.6	61.3	63.0	64.7
Quebec	58.5	61.2	63.9	65.1	66.4	67.7
Ontario	64.2	66.4	68.6	69.3	70.0	70.7
Prairie	60.0	62.5	65.2	66.3	67.4	68.5
Alberta	65.8	67.8	69.9	70.4	71.0	71.5
B.C. & Territories	61.3	63.7	66.3	67.3	68.3	69.3
			(index)			
Atlantic	1.00	1.06	1.12	1.15	1.18	1.21
Quebec	1.00	1.05	1.09	1.11	1.14	1.16
Ontario	1.00	1.03	1.07	1.08	1.09	1.10
Prairie	1.00	1.04	1.09	1.11	1.12	1.14
Alberta	1.00	1.03	1.06	1.07	1.08	1.09
B.C. & Territories	1.00	1.04	1.08	1.10	1.11	1.13

SOURCE: Canadian Resourcecon Limited, and (1) Statistics Canada, Catalogue 11-003E, Canadian Statistical Review.

TABLE 90: LABOUR FORCE IN GOODS PRODUCING INDUSTRIES

	1951	1961	1971	Average Change 1951-1961	 1961-1971
		(percent of total)		(percent per annum)	
Atlantic	49.9	37.5	31.3	-1.24	-0.62
Quebec	53.5	44.9	34.3	-0.86	-1.06
Ontario	51.8	42.8	35.9	-0.90	-0.69
Prairie	52.4	43.8	36.0	-0.86	-0.78
Alberta	51.7	40.9	33.5	-1.08	-0.74
B.C.	43.8	35.6	30.8	-0.82	-0.48
Canada	51.5	42.2	34.4	-0.93	-0.78

SOURCE: Statistics Canada, Catalogue 94-739, Industries, Historical, For Canada and Provinces, 1951-1971.

NOTE: Goods producing industries as shown exclude utilities; residual (service industries) includes utilities.

TABLE 91: LABOUR FORCE IN GOODS PRODUCING INDUSTRIES

	1975	1976	1977	Average Change 1975-1977
		(percent)		(percent per annum)
Atlantic(1)	30.6	29.7	28.4	-1.10
Quebec	34.5	34.9	33.2	-0.65
Ontario	35.6	36.0	35.5	-0.05
Prairie(1)	36.9	34.3	34.4	-1.25
Alberta	34.8	36.0	33.3	-0.75
B.C.	29.2	30.2	30.0	-0.40
Canada	34.3	34.5	33.5	-0.40

SOURCE: Statistics Canada, Catalogue 71-001, The Labour Force, January 1978.

NOTE: Statistical basis for the percentage shares varies somewhat from Table 91; however shifts (percent per annum) are considered comparable.

(1) Weighted average using labour force data from Statistics Canada, Catalogue 11-003E.

TABLE 92: ESTIMATED FUTURE SHARE OF LABOUR FORCE IN GOODS-PRODUCING INDUSTRIES, 1980 TO 2000

	1975 (1)	1980	1985	1990-2000
			(percent of total)	
Atlantic	30.6	27.8	25.8	24.9
Quebec	34.5	31.3	29.2	28.1
Ontario	35.6	32.3	30.1	29.0
Prairie	36.9	33.5	31.2	30.1
Alberta	34.8	31.6	29.4	28.4
B.C. & Territories	29.2	26.5	24.7	23.8
			(index)	
all regions	1.00	0.908	0.846	0.815

SOURCE: Canadian Resourcecon Limited and (1) from Table 91.

TABLE 93: GOODS-PRODUCINGS INDUSTRY, TRENDS IN OUTPUT PER PERSON EMPLOYED, CANADA 1947-1976 (1)

		Average Annual % Change
(a) Long-term trends:		
	1947-1977	4.4
	1947-1957	5.4
	1957-1967	4.6
	1967-1977	3.2
(b) Recent years:		
	1972-1973	4.0
	1973-1974	-0.2
	1974-1975	-1.5
	1975-1976	3.8
	1976-1977	1.6
	1972-1977	1.5

SOURCE: Statistics Canada, Catalogue 14-201, Aggregate Productivity Measures 1946-1976, and unpublished data from Statistics Canada.

(1) Output measured in terms of constant price Gross Domestic Product at factor cost (Real Domestic Product).

Table 94 summarizes a forecast of output of the goods-producing industries for the period from 1975 to 2000. The forecast takes into account, as detailed above, regional population projections and estimates of participation rates, the share of the labour force in goods-producing industries, and the change in productivity per worker. Forecast output is indicated in the form of an index relative to 1975 output.

TABLE 94: FORECAST OF OUTPUT OF GOODS-PRODUCING INDUSTRIES

	1975	1980	1985	1990	1995	2000
			(indexed)			
Atlantic	1.00	1.24	1.53	1.83	2.21	2.70
Quebec	1.00	1.19	1.43	1.64	1.97	2.34
Ontario	1.00	1.20	1.47	1.72	2.05	2.45
Prairie	1.00	1.19	1.46	1.70	2.01	2.42
Alberta	1.00	1.34	1.77	2.32	3.00	3.81
B.C. & Territories	1.00	1.22	1.55	1.93	2.41	3.01

SOURCE: Canadian Resourcecon Limited.

(b) Energy Conservation

Industrial energy users can be expected to reduce energy consumption in response to higher prices through energy conservation measures ranging from housekeeping improvements in the short term to major capital expenditures in the longer term. In an aggregate category such as the general industrial sector, energy conservation measures cannot be identified in any way which would allow analytical assessment of their impact. For industry in general the Office of Energy Conservation set a target during a 1976 conference on industrial energy conservation of reducing the increase in energy use to 2.0 percent per annum through the period from 1975 to 1990.* On this basis energy consumption per unit of output would have to be reduced by 25 to 35 percent. For the general industrial sector it is assumed that the sector will be typical of the broader category of all industries, and that the target will be achieved. Indexed levels of energy use per unit of output are estimated as:

	index
1975	1.00
1980	0.90
1985	0.80
1990-2000	0.75

(c) Forecast Energy Requirements

Taking into account the forecast of industrial output (Table 94), and the impact of energy conservation measures, industrial energy requirements may be forecast to grow according to the index levels shown in Table 95. These index levels may then be applied to the 1975 base year levels of energy consumption in the general industrial sector to provide the forecast of future general industrial energy requirements as outlined in Table 96.

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* *EMR Canada, Office of Energy Conservation,* *Second Conference on Industrial Energy Conservation, March 24, 1976.*

TABLE 95: FORECAST GROWTH OF ENERGY REQUIREMENTS IN THE GENERAL INDUSTRIAL SECTOR, 1980 TO 2000

	1975	1980	1985	1990	1995	2000
				(index)		
Atlantic	1.00	1.12	1.22	1.37	1.66	2.03
Quebec	1.00	1.07	1.14	1.23	1.48	1.76
Ontario	1.00	1.08	1.18	1.29	1.54	1.84
Prairie	1.00	1.07	1.17	1.28	1.51	1.82
Alberta	1.00	1.21	1.42	1.74	2.25	2.86
B.C. & Territories	1.00	1.10	1.24	1.45	1.81	2.26

SOURCE: Canadian Resourcecon Limited.

TABLE 96: FORECAST GENERAL INDUSTRIAL SECTOR FOSSIL FUEL(1) REQUIREMENTS, 1980 TO 2000

	1975(2)	1980	1985	1990	1995	2000
				(10^{12} Btu's)		
Atlantic	14.6	16.3	17.8	20.0	24.2	29.6
Quebec	119.7	128.1	136.4	147.2	177.1	210.6
Ontario	219.7	237.2	259.2	283.4	338.3	404.2
Prairie	36.3	38.8	42.4	46.4	54.7	66.0
Alberta	61.6	74.5	87.4	107.1	138.5	176.1
B.C. & Territories	28.3	31.2	35.1	41.1	51.3	64.0
Canada	480.1	526.1	578.3	645.2	784.1	950.5

SOURCE: Canadian Resourcecon Limited, and (2) from Table 85.

NOTES: (1) Includes selected fuels as outlined for Table 85 (coal, LFO, HFO, natural gas).

(d) Potential Coal Demand

In 1965, several years after natural gas service had been extended from Alberta eastward to Ontario and westward to British Columbia, 13 percent of the energy requirements of the general industry category of demand was supplied by coal (Table 86). Based on this evidence it will be assumed that 25 percent of the energy users in this sector could utilize coal as an energy source by virtue of either their larger size, appropriate technology, or non-urban locations - if the price is right. The other 75 percent of this market, estimated at a total 950 x 10^{12} Btu of fossil fuel in 2000 (Table 96), will arbitrarily be excluded as a potential coal market within the forecast oil/gas price framework specified in this analysis.

At oil and gas prices which at a maximum are forecast to reach some $3.50/MMBtu (1978$) to the smaller class of industrial customer, from southern Ontario eastward, by 1990 (Chapter III, 2.0), the potential may exist for some reintroduction of coal into this market segment.

Coal could be utilized in direct combustion processes or through proven small scale gasification processes such as Wellman-Galusha or Winkler.

Dealing with the use of coal by direct combustion processes, it will be assumed coal conversion costs for smaller users will be at the high end of the cost scale calculated above (Chapter III, Table 12) for industrial boiler conversions - say $2.15/MMBtu's. For new plant situations the price of coal would have to be discounted by at least $1.50/MMBtu.

Concerning coal gasification, commercial processes are available today for producing low or intermediate Btu gas on a small scale - say 1 MM cf/d minimum. Based on very limited cost information the gasification costs of such systems installed in new plant situations have been calculated to range from $1.50 to $2.50/MMBtu's, including all capital ammortization costs and operating costs but exclusive of coal costs.* The lower end of the range would apply to raw gas and the higher end to clean gas.

All existing plants therefore will require a coal price discount from oil or gas prices of $2.15/MMBtu or more for coal to be economic. For new plants, from 1980 onwards, coal price discounts will have to range from $1.50 to $2.50/MMBtu's for coal to be competitive depending on whether coal can be utilized by direct combustion or whether it must be gasified prior to consumption.

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10.0 SUMMARY OF POTENTIAL INDUSTRIAL COAL DEMANDS

Table 97 summarizes the total Canadian potential thermal coal demands by industry sector. Table 98 shows the regional distribution of potential coal demand by industry group for the year 1990. It is to be emphasized that the potential demand figures summarized here are only a measure of the technological potential of industry to use coal.* They must not be construed as estimates of coal volumes which could be economically utilized - at least not under the base case structure of energy prices forecast in this study.

Chapter VII, the net-back analysis, will give an indication of what portion of these volumes might be economically served by Canadian coal sources, taking transportation costs and industrial coal conversion costs into account.

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* *The totals for 1980 and 1985 in fact should not even be viewed as technologically achievable as conversions to such quantities could not physically be made this quickly even assuming the price incentive was present.*

TABLE 97: SUMMARY OF POTENTIAL INDUSTRIAL COAL DEMANDS CANADA 1980-2000

	1980	1985	(10^{12} Btu) 1990	1995	2000
Pulp and Paper	147.9	134.6	123.9	120.9	107.9
Cement	47.4	50.3	52.4	54.1	53.0
Lime	10.8	11.6	12.7	13.8	14.9
Chemicals	172.0	249.0	288.0	299.0	311.0
Steel	5.0	18.6	27.9	37.3	42.3
Oil Sands	-	33.5	67.0	67.0	100.5
Smelting and Refining	36.9	40.9	43.8	45.2	46.4
Potash	17.5	22.6	22.9	24.1	25.5
General Industrial	131.5	144.6	161.3	196.0	237.6

TABLE 98: 1990 SUMMARY OF POTENTIAL INDUSTRIAL COAL DEMAND (10^{12} Btu)

Region	Pulp and Paper	Cement	Lime	Chemicals	Steel	Oil Sands	Smelting and Refining	Potash	General Industry	Provincial Total
British Columbia		4.4	0.2	13.0			1.0		10.3	28.9
Prairies	5.9			77.8					38.4	122.1
Alberta		10.1	1.0			67.0				78.1
Saskatchewan		1.6			8.6			21.2		31.4
Manitoba		2.7	0.6				6.6			9.9
Ontario	39.7	17.0	7.0	144.0	19.3		13.3		70.8	311.1
Quebec	46.5	14.0	3.7	44.6			21.3		36.8	166.9
Atlantic	31.8	2.6		8.6					5.0	48.0
New Brunswick			0.2					1.7		1.9
Industry Total	123.9	52.4	12.7	288.0	27.9	67.0	42.2	22.9	161.3	798.3

CHAPTER V

THERMAL ELECTRIC MARKETS

Canada is presently in the enviable position of generating most of its electrical energy requirements from hydroelectric sources (72 percent during 1976). However, with most of the prime hydroelectric sites already developed, an increasing proportion of future capacity additions will be based upon thermal electric generating technologies. This chapter projects the probable coal requirements for thermal electric generation in each province.

In the shorter term, over the next ten years, projections of thermal electric coal demands are largely based upon utility forecasts of the requirements of specific coal-fired additions which have already been approved or are in the planning stages. Over the longer term, from 1990 to 2000, coal requirements are forecast mainly on the basis of the anticipated cost of coal-fired generation relative to that of other alternatives. This assessment was made after discussions with utility officials and a review of published sources. In addition, the ability of the indigenous coal reserves of each province to support coal-fired capacity was also considered as possible constraint on future thermal electric coal use.

A range of coal requirements, rather than a single figure, is used in forecasting the thermal electric markets of most provinces to reflect the possible variations in demand that could result from changes in forecast electricity demands or in fuel choice for thermal generation. Projected thermal electric coal requirements by province are summarized in Table 102.

1.0 BRITISH COLUMBIA

1.1 Present and Projected Electric Energy Requirements

B.C. Hydro, the major utility in the province, currently projects a growth rate in excess of 6 percent per annum over the next decade. In contrast, the B.C. Energy Commission has projected that electricity requirements from 1977-1992 will increase by 3.4 to 3.8 percent annually. The latter rate is close to that actually experienced over the past 4 years as provincial electricity use increased from about 32.9 terawatt-hours (Twh) in 1973 to 38.4 Twh in 1977.*

1.2 Projected Coal Requirements

At present there are no coal-fired power plants in British Columbia and it has been estimated that there are about 80 million kilowatts of undeveloped hydro potential in the province,** far more than enough to meet load growth over the forecast period. However, since many of the remaining hydro sites have high capital costs or unacceptable environmental impacts associated with them, thermal electric alternatives have begun to receive consideration in recent years. Based upon a comparison of the projected capital costs of nuclear plants to those of alternative technologies (coal and hydro), it has been concluded that nuclear power is unlikely to even begin to be considered as an economic alternative before the middle '90's.*** Given the high cost of fuelling stations burning oil or natural gas, coal-fired plants are the most attractive alternative to hydroelectric capacity since the province possesses large and accessible thermal coal reserves.

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* *Statistics Canada, Catalogue 57-204, Annual, Electric Power Statistics, Volume 1, 1977. p. 39.*

** *R.W. Bonner (Chairman, B.C. Hydro) in a Presentation to the Canadian Electrical Association, 1976.*

*** *G.J. Protti, Canadian Electric Utility Costs, 1960-1990, Working Paper No. 78-4, Canadian Energy Research Institute, May 1978, p.165.*

There are currently two possible coal-fired projects under consideration in B.C., neither of which would be required until the late 1980's since projects already under construction will meet the anticipated demand to that time. The possibility of a 2000 MW plant sited at Hat Creek to utilize adjacent low-grade* coal deposits has been under study, since 1974, but no decision as to whether the development will proceed has yet been made, although one is expected during 1979. If developed, the project would consume about 11.9 million tons (130 x 10^{12}Btu) of the coal per year**, but would not be in-service before the late 1980's. Also under study is a 600 MW plant in the East Kootenays, which would burn waste from Kaiser Resources' metallurgical coal cleaning plant at Sparwood at the rate of about 2.87 million tons (7,900 Btu/lb), or about 45 x 10^{12}Btu, per annum.*** Again, however, this plant would not be in-service until 1987 at the earliest, and is considered only a possibility at present.

Given the fact that B.C. Hydro has established a thermal division, it is probable that the utility is sufficiently committed to coal-fired power to build either one or the other of the two projects described earlier, but not both. While B.C. Hudro's current plans call for the projects to be in-service in the late 1980's, if constructed, the utility's forecast of electric requirements appears high in comparison to that of the B.C. Energy Commission, as noted earlier. Hence, a somewhat later in-service date of 1990 has been adopted herein for a coal-fired addition to the generating capacity of the province. It is expected that further capacity additions throughout the forecast period will be hydroelectric. Coal use for thermal electric generation in British Columbia is therefore forecast to range from 45 to 130 x 10^{12}Btu (depending upon which project is built), beginning in 1990 and remaining constant to 2000.

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* *5,500 Btu/lb., 32.5% ash content, 22.5% equilibrium moisture content.*

** *Based on a daily coal requirement of 50 thousand tons and an annual capacity factor of 65%.*

*** *Personal communication, B.C. Hydro.*

2.0 ALBERTA

2.1 Present and Projected Electric Energy Requirements

The projections of electric energy requirements and associated coal requirements for the province of Alberta, as detailed in the current Alberta Energy Resources Conservation Board energy requirements forecast, have been adopted herein.* The Board expects that electrical requirements of the interconnected system will increase from 16.7 terawatt-hours (Twh) in 1977 to 44.0 Twh by 1990 and 72.3 Twh by the year 2000. These projections represent an overall growth rate of 6.6 percent per annum from 1977-2000; 7.7 percent from 1977-1990, and 5.1 percent from 1990-2000.

2.2 Evaluation of Alternative Technologies

Over the first portion of the forecast period to 1990, the ERCB anticipates that virtually all of the incremental capacity required to satisfy the projected demand will be derived from coal-fired plants. No new major gas-fired base-load plants beyond those in place or approved are expected to be built in the future. In fact, the Board believes that the increased price of gas will substantially reduce the use of gas for base-load generation by 1990, with existing gas-fired plants moving towards a peaking role. In new coal-fired plants, a small proportion of total fuel requirements will be derived from natural gas as a start-up and flame stabilization fuel. While there are several major undeveloped hydroelectric sites (including Dunvegan on the Peace River, and Mountain Rapids on the Slave) which are economically attractive, it is unlikely that any major hydro project will be operational before 1990, given the long lead times required. From 1990 to 2000, however, almost 40 percent of the incremental energy requirement will be derived from hydroelectric sources, in the opinion of the ERCB.

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* *Alberta Energy Resources Conservation Board, Energy Requirements in Alberta, 1977-2006, September 1978.*

Oil is not currently used in significant quantities as a fuel in Alberta thermal electric plants, given its higher price relative to natural gas. Since this interfuel price relationship is expected to continue in the future, oil is not included as a fuel in the ERCB's forecast of energy resource requirements for electric end-use. Similarly, the Board considers it unlikely that nuclear power will be introduced in Alberta during the forecast period, given the availability of large, low-cost, indigenous coal reserves. Hence, coal is forecast to supply the bulk of the energy resource requirements for electricity generation in Alberta over the forecast period.

2.3 Projected Coal Requirements

The ERCB has forecast thermal electric coal demand to the year 2006, using a heat value of 16 million Btu/ton as representative of Alberta's sub-bituminous coal reserves suitable for thermal electric fuel use. Table 99 details the portion of the board's forecast which covers the time frame of this study. The share of total electric requirements generated from coal increases from about 62 percent in 1976 to more than 80 percent in the year 2000, with associated coal requirements rising from 6.6 million tons in 1976 to 36.8 million tons by the end of the forecast period. Coal use is shown to increase steadily over the forecast period except during 1990 and 1991 and 2000 and 2001, when large increments of hydroelectric capacity is forecast to come on-stream, temporarily reducing or slowing the

TABLE 99: FORECAST THERMAL ELECTRIC COAL REQUIREMENTS - ALBERTA, 1977-2000

Year	Total Gwh	Coal		
		Gwh	10^6 tons*	10^{12} Btu
1976	15,400	9,480	6.6	105.6
1977	16,720	11,830	8.4	134.4
1978	18,740	13,520	9.4	150.4
1979	20,340	14,780	10.1	161.6
1980	22,210	17,090	11.5	184.0
1981	24,330	19,200	12.7	203.2
1982	26,000	21,100	13.7	219.2
1983	27,440	22,590	14.5	232.0
1984	29,410	24,630	15.7	251.2
1985	32,180	27,460	17.5	280.0
1986	25,680	30,970	19.7	315.2
1987	38,170	33,520	21.3	340.8
1988	39,670	35,180	22.4	358.4
1989	40,930	36,820	23.4	374.4
1990	44,040	36,200	23.0	368.0
1991	47,280	35,410	22.6	361.6
1992	50,350	38,440	24.3	388.8
1993	51,940	40,020	25.3	404.8
1994	54,480	42,550	26.9	430.4
1995	56,830	44,900	28.3	452.8
1996	60,110	48,150	30.4	486.4
1997	63,450	51,460	32.5	520.0
1998	66,830	54,800	34.6	553.6
1999	69,040	56,990	36.0	576.0
2000	72,270	58,200	36.8	588.8

SOURCE: Alberta Energy Resources Conservation Board, Energy Requirements in Alberta, 1977-2006, September 1978.

* *Coal tonnage calculated on basis of coal calorific value of 16 x* 10^6 *Btu/ton.*

increase in coal requirements. Should these hydroelectric projects fail to proceed, an additional 6.3 million tons of coal would be required by the year 2000.

3.0 SASKATCHEWAN

3.1 Present and Projected Electric Energy Requirements

While electricity requirements in Saskatchewan doubled over the past decade, they are projected to increase at a more moderate rate in the future, consistent with expectations of slower growth in most other provinces. The current Saskatchewan Power Corporation forecast shows electricity requirements increasing from an expected 8.3 terawatt-hours (Twh) in 1978 to about 12.8 Twh in 1988, an average annual increase of about 4.4 percent.* Over the longer term, the Saskatchewan Power Corporation forecasts that electricity demand will reach about 20.2 Twh by the year 2000, an average annual growth rate in the order of 4.1 percent over the projected 1978 base.

3.2 Present Coal Requirements and Short Term Additions

Saskatchewan, which already generates the majority of its electrical requirements from coal, used about 0.55 million tons of sub-bituminous coal and 3.35 million tons of lignite for this purpose during 1976. With the start-up of the 300 MW lignite-fired Boundary Dam unit during 1977, lignite use increased to over 4 million tons, while the use of sub-bituminous coal from Forestburg, Alberta rose to about 0.73 million tons in order to compensate for the drop in hydro-electric generation due to unusually low water flows.** Since the fuel and maintenance cost of generating electricity from Alberta coal is about 12.9 mills/Kwh at the Queen Elizabeth plant versus 3.7 mills/Kwh from Saskatchewan lignite at

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* *Saskatchewan Power Corporation Forecast: Electricity & Natural Gas, 1978-1988*, September 1978.

** *Statistics Canada, Catalogue 57-003. Quarterly Report on Energy Supply-Demand in Canada*, 1977, p. 203.

Boundary Dam, Alberta coal will be used only for peaking and emergencies during the future.* Hence, the 1977 level of consumption is not representative of the average long-term requirement as it occurred during a year of low flow.

The use of Saskatchewan lignite is expected to increase by about two million tons per year with the start-up of the Saskatchewan Power Corporation's 300 MW Poplar River thermal electric plant scheduled for late 1979.** This station, near Coronach in southern Saskatchewan, will be fired with lignite coal (5,500 Btu/lb.) from an adjacent mine developed to fuel the plant. A second 300 MW lignite unit could be in-service at Poplar River by 1982, provided that a current dispute with Montana over potential impacts on air and water quality is resolved to the satisfaction of the International Joint Commission.*** Lignite requirements for this unit would also be about two million tons per year, bringing total provincial requirements to more than 8 million tons by 1984.

3.2 Longer Term Additions, 1985-2000

The Saskatchewan Power Corporation has projected two alternative scenarios for generation mix to the year 2010. In one, the "minimum coal" scenario, it is assumed that remaining hydroelectric resources will be fully exploited, with nuclear power coming on-line in 1996 to not only meet the incremental demand, but also displace much of the energy from coal-fired generation. This scenario is shown in Table 100. Since

* *Personal communication, Saskatchewan Power Corporation, January 1979.*

** *Dames & Moore, op.cit.*

*** *Financial Post, Feb. 4, 1978, p. 36.*

TABLE 100: FORECAST THERMAL ELECTRIC COAL REQUIREMENTS - SASKATCHEWAN, 1977-2000

Year	Scenario "B" (Minimum Coal)		Scenario "A" (Maximum Coal)	
	10^3 tons	10^{12} Btu (2)	10^3 tons	10^{12} Btu (2)
1977 (1)	4,741	62.4	4,741	62.4
1978	6,201	68.2	6,201	68.2
1979	6,620	72.8	6,620	72.8
1980	7,036	77.4	7,036	77.4
1981	7,191	79.1	7,191	79.1
1982	7,099	78.1	7,099	78.1
1983	7,702	84.7	7,702	84.7
1984	8,167	89.8	8,167	89.8
1985	8,097	89.1	8,632	95.0
1986	8,027	88.3	9,907	101.2
1987	8,490	93.4	9,560	105.2
1988	8,955	98.5	10,025	110.3
1989	9,420	103.6	10,490	115.4
1990	9,885	108.7	10,955	120.5
1991	10,430	114.7	11,500	126.5
1992	10,996	121.0	12,066	132.7
1993	11,586	127.4	12,656	139.2
1994	11,664	128.3	13,269	146.0
1995	11,767	129.4	13,907	153.0
1996	10,468	115.1	14,570	160.3
1997	9,195	101.1	15,259	167.8
1998	9,913	109.0	15,977	175.7
1999	8,696	95.7	16,722	183.9
2000	7,511	82.6	17,499	192.5

SOURCE: Saskatchewan Power Corporation, February 1978.

NOTES:

(1) Actual (Statistics Canada, Catalogue 57-003, op.cit.).

(2) Average heating value of 11 million Btu/ton, except for 1977 where sub-bituminous coal was converted to Btu's on the basis of 15.2 million Btu/ton and lignite, on the basis of 12.8 million Btu/ton.

formulation of this scenario, the Saskatchewan government has subsequently accepted the recommendation of a board of inquiry that further development of the Churchill River is not appropriate at this time. However, development of the river at a later date has not been entirely ruled out, so the projected coal requirements shown in Table 100 have not been adjusted, although the short-term impact of such a deferral would be to increase coal requirements by more than one million tons per annum.*

The "maximum coal" scenario assumes that coal will supply all of the energy resource requirements for incremental electricity demand except for a small portion to be met by the 100 MW Island Falls project which is currently under construction. No nuclear power would be developed in this case.

Until 1984 the two scenarios are identical, but the assumed addition of hydroelectric capacity in 1985 causes a divergence thereafter. The major difference in coal requirements of the two cases is a result of the assumed addition of nuclear capacity after 1995 - scenario "A" coal requirements are shown to be more than twice those of scenario "B" in the year 2000.

At present, the cost of coal-fired base load generation in Saskatchewan appears to be cheaper than nuclear power. A cost of $500/kw (current dollars) has been projected for the second unit of the Poplar River station planned to be in operation by 1982.** Assuming a 10.6 percent p.a. interest and amortization cost, the capital cost component works out to about $53/kw/annum. Adding to this an operation and maintenance cost of $18/kw/annum*, the total non-fuel cost becomes $71/kw/annum. On the basis of an 80 percent capacity factor, total non-fuel costs work out to about 10.1 mills/Kwh. The cost of coal at Poplar River is expected to be in the order of $5 to $6/ton of 11 million Btu's.** Given a heat rate of 11,000 Btu/Kwh*** and a coal cost of $6/ton, the fuel cost is calculated to be 6 mills/Kwh, bringing total generation costs to 16.1 mills/Kwh. By comparison it is estimated that the total cost of generating electricity in a nuclear station would at least be 20 mills/Kwh.****

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* *Personal communication, Saskatchewan Power Corporation, January 1979.*

** *Protti, op.cit., p. 204.*

However, as conjectured by others, it is entirely possible that the price of Saskatchewan coal could follow the rapid rise in oil and natural gas prices,***** eroding the competitive advantage currently possessed by coal-fired generation relative to nuclear. In view of the uncertainty in relative fuel price movements during the rather long time horizon over which this forecast extends, it is concluded that both the nuclear and non-nuclear scenarios of future generation mix are equally plausible. Thermal electric coal requirements by the end of the forecast period are detailed in Table 100.

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* *Canadian Resourcecon estimate.*

** *Coal cost obtained from Saskatchewan Power Corporation in a January 1979 discussion.*

*** *Heat rate used by SPC in projecting coal requirements shown in Table 100.*

**** *Canadian Resourcecon estimate.*

***** *Protti, op.cit., p. 217.*

4.0 MANITOBA

4.1 Present and Projected Electric Energy Requirements

During 1977 about 12.3 terawatt-hours of electric energy was consumed in Manitoba, an increase of about 6.2 percent per annum over the past decade, while peak load within the province increased at about 8 percent per annum over the same period, to more than 2,500 MW in 1977. From 1975 to 1977, however energy use in the province has increased by less than 1.5 percent per annum, while the peak load increased by about 4 percent.* Current forecasts by Manitoba Hydro call for an average growth rate in the order of 5 percent over the next 20 years.

4.2 Projected Coal Requirements to 1990

There are currently two coal-fired plants in Manitoba - a 237 MW unit at Brandon and a 132 MW station at Selkirk. In 1977 about 1.23 million tons of lignite from Estevan, Saskatchewan, were burned in these plants,** a large increase from 0.37 million tons two years previously.*** This rapid increase in coal use, however, was necessitated by unusually low water levels during 1976 and 1977. Therefore, 1977 volumes cannot be considered indicative of the long-term requirements of existing plants which may be expected to fluctuate widely, not only as a result of varying flow conditions, but also as a result of new blocks of hydraulic power coming on-line, decreasing the need for thermal electric generation until load growth catches up to hydroelectric capacity. On the average, thermal coal requirements are not expected to exceed 300 tons, or 4.3 x 10^{12}Btu, annually.*

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* *Statistics Canada, Catalogue 57-204, Annual, Electric Power Statistics, Volume 1, 1977, pp. 32-33.*

** *Statistics Canada, Catalogue 57-003, Quarterly, Quarterly Report on Energy Supply-demand in Canada, 1977, p. 197.*

*** *Statistics Canada, Catalogue 57-002, Annual, Electric Power Statistics, Volume 2, 1975, p. 39.*

In view of the reduced rates of recent years and large amounts of undeveloped capacity remaining on the Nelson River, Manitoba Hydro does not plan to add any significant amounts of thermal capacity before 1990.** Hence, coal requirements are projected to remain at the quantity forecast for use in existing plants.

4.3 Longer Term Additions, 1990-2000

It now appears that hydroelectric generation will be able to meet Manitoba Hydro's electrical energy requirements until at least the mid-1990's.*** At that time a 700 MW thermal addition, of either coal-fired or nuclear design, could be required given current load growth forecasts. Even if coal is the chosen fuel, however, the plant is expected to operate at a low capacity factor during its initial years. On the basis of a 30 percent annual capacity factor, and a heat rate 13,600 Btu/Kwh, coal requirements for such a plant would be in the order of 21.4 x 10^{12}Btu, or 1.5 million tons.**** Total coal use by the year 2000 could thus be as high as 26 x 10^{12}Btu, or 1.8 million tons.

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* *Personal communication, Manitoba Hydro, January 1979. Conversion from tons to Btu's made on the basis of 8,140 Btu/lb. (Statistics Canada, Catalogue 57-202, op.cit., 1976).*

** *Protti, op.cit., p. 200.*

*** *Toronto Globe and Mail, November 2, 1977.*

**** *The heat rate for lignite-fired plants in Manitoba was 13,636 Btu/Kwh during 1976, with an ACF of about 35%. (Statistics Canada, Catalogue 57-202, op.cit., 1976). If constructed, a mine-mouth location in Saskatchewan is a definite possibility, since the trade-off between the reduction in coal transportation costs and the increase in extra transmission costs would likely reduce the overall cost of delivered power (personal communication, Manitoba Hydro, January 1979).*

When the minimal increases in provincial energy requirements during recent years (about 1.1 percent from 1975-77) are compared to current forecasts of load growth in the order of 5 percent, however, the question arises as to whether an additional thermal project will even be required before the year 2000. If this factor is considered together with the possibility that the project could be nuclear instead of coal-fired, it becomes evident that the preceding estimate should be regarded as the upper limit of the probable range of coal use by the end of the forecast period.

5.0 ONTARIO

5.1 Present and Projected Electric Energy Requirements

During 1977, about 98.3 Twh of electrical energy were used in Ontario, while the firm peak power load within the province was in the order of 16,500 megawatts.* Ontario Hydro's most recent forecast of electric energy requirements to the year 2000 is predicated on an average annual growth rate in the order of 5.3 percent.** While this is much lower than past load forecasts, which prior to 1976 exceeded 7 percent, it still exceeds the rate of 4.0 percent considered most probable by the Porter Commission.*** By the year 2000 Ontario Hydro's load forecast would be about 25 percent higher than that of the Porter Commission. The sensitivity of thermal electric coal consumption to such changes in assumed growth rates, as well as to changes in generation mix, is briefly discussed in a later section.

5.2 Projected Coal Requirements to 1990

While Ontario has been using large quantities of coal in thermal electric generation over the last decade, the overwhelming majority of coal used to date has been imported from the United States. During 1977, less than 0.25 million tons, or about 2½ percent of the 9.7 million tons of coal used in thermal plants in Ontario, was derived from Canadian sources.****

* *Statistics Canada, Catalogue 57-204, Annual, Electric Power Statistics, Volume 1, 1977, pp. 30-31.*

** *Royal Commission on Electric Power Planning, Interim Report on Nuclear Power In Ontario, September 1978, p. 21.*

*** *Ibid, p. 23.*

**** *Statistics Canada, Catalogue 57-003, Quarterly, Quarterly Report on Energy Supply-Demand in Canada, 1977, p. 191.*

Prompted by soaring U.S. coal costs of recent years and the need to burn lower sulphur coals to meet emission standards, however, Ontario Hydro has made the decision to diversify its sources of coal supply by drawing a larger share of its requirements from Western Canada.* During 1979 the use of Western Canadian coal in Ontario thermal plants should rise sharply as the full scale movement of this coal, begun in July 1978, continues into its first full year of operation. About 2 million tons per year of high volatile bituminous coal (11,000 Btu/lb.) are scheduled to be supplied from the Coal Valley, Alberta mine of Luscar Sterco Ltd., while Byron Creek Collieries Ltd. near Corbin, B.C. will provide about 700 thousand tons per year of medium-volatile bituminous coal (11,700 - 12,000 Btu/lb.).** Total Canadian coal use by Ontario Hydro in 1979 is thus expected to reach 2.7 million tons, or about 60 x 10^{12}Btu annually. The Western Canadian coal will be transported to Ontario Hydro's 4000 MW coal-fired plant at Nanticoke and blended with higher Btu (13,000/lb.) U.S. bituminous coal.

In 1980, shipments of lignite (7,200 Btu/lb.) from Bienfait, Saskatchewan are scheduled to start for use in Ontario Hydro's 310 MW Thunder Bay Extension plant. The first unit is due to come on-line in October 1980, followed by the second in April 1981.*** Annual lignite requirements will be in the order of 1 million tons, or 14.4 x 10^{12}Btu's in 1982 when the plant operates both units for a full year, and remain fairly constant thereafter.

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* *The cost of U.S. coal to Ontario Hydro increased from $14/tonne in 1973 to $36/tonne four years later. (Dames & Moore, A Report on the Current Status of the Canadian Coal Mining Industry, May 1978. p. 30.*

** *E.G. Bazeley, Fuels Division, Ontario Hydro, "A Supply System for Western Canadian Thermal Coal", April 1977 (mimeographed).*

*** *Personal communication with Ontario Hydro, January 1979.*

Ontario Hydro also plans to develop a 400 MW lignite-fired plant at Atikokan, with the 4 units coming in-service between April 1983 and October 1984. Fuel requirements are expected to be in the order of 1.3 million tons per annum when the plant begins full operation in 1985.* By 1985, therefore, Ontario Hydro's thermal electric plants will consume 2.7 million tons of Western Canadian bituminous coal and about 2.3 million tons of Saskatchewan lignite annually, with a total heating value in excess of 90×10^{12}Btu. No further increase in this requirement is expected until beyond 1990, since no other coal-fired additions are expected before then in light of the recent downward revision in the utility's demand forecast.**

5.3 Longer Term Additions, 1990-2000

Beyond 1990 the increase in coal requirements of Ontario thermal electric plants is difficult to predict since planning policies are very much in a state of flux at present, with the Royal Commission on Electric Power Planning yet to deliver its final recommendations to the provincial government. Therefore, this section outlines the projected thermal electric coal requirements for two alternate scenarios: Ontario Hydro's current generation programme, and the programme recommended on an interim basis by the Porter Commission.

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* *Calculated from a recent paper by Ontario Hydro's Director of Fuels. (J.G. Matthews, "A Challenge for Canadian Thermal Coal: Accomplishments, Concerns and Opportunities", Presentation prepared for the Canadian Coal Conference, September 1978, Sydney, N.S.).*

** *Personal communication, Ontario Hydro, January 1979.*

Ontario Hydro's Programme

Ontario Hydro's future programme beyond that now presently authorized, is based upon the use of nuclear units for base load generation, and coal-fired units for intermediate and peak loads. Table 101 shows Ontario Hydro's most recent forecast of coal supply and demand to the year 2000 under these premises.

Canadian coal use by the year 2000 is expected to be 91 x 10^{12} Btu at the very least, since most of this volume has already been contracted to fuel generating stations under construction. Primary coal demand is shown to be 538 x 10^{12}Btu by the year 2000 in Table 101, leaving a supply gap of 161 x 10^{12} Btu to be filled over presently-contracted U.S. and Canadian volumes. If all of this deficit were to be provided from Canadian sources, the volume of Canadian coal used in Ontario thermal electric plants by the year 2000 would rise to 252 x 10^{12}Btu.

However, it has been stated that "the concern for security which was Ontario Hydro's primary reason for turning to Canadian coal is essentially satisfied by what is already done or underway".* Hence, if U.S. coal is available at lower cost, Ontario Hydro is not likely to purchase higher-cost Canadian supplies. Current projections support the view that Canadian coal will indeed continue to be more costly than American coal.**

An Ontario Hydro projection of the comparative 1987 costs per kilowatt-hour of electricity generated from U.S. and Western

* *Matthew, op.cit., p. 19.*

** *Ibid., slide 4; Protti, op.cit., p. 213.*

TABLE 101: FORECAST ANNUAL COAL DEMAND AND SUPPLY FOR THERMAL ELECTRIC GENERATION IN ONTARIO(1)

10^{12}Btu(2)

Year	Primary Coal Demand(3)	Electricity Exports	U.S. Coal Supply	Canadian Coal Supply
1978	182	96	286	3
1979	234	78	286	60
1980	278	68	286	70
1985	315	?	286	91
1990	328	?	286	91
1995	390	?	286+	91+
2000	538	?	286+	91+

(1) *Source: J.G. Matthews, Director of Fuels, Ontario Hydro, "A Challenge For Canadian Thermal Coal: Accomplishments, Concerns and Opportunities", Presentation Prepared for The Canadian Coal Conference, September 1978, Sydney, Nova Scotia.*

(2) *Figures in this table were converted from tons in the original source on the basis of 26 million Btu/ton.*

(3) *For domestic Ontario electricity demand only.*

Canadian coals, forecasts that U.S. bituminous coal will continue to maintain a clear cost advantage over western Canadian bituminous and sub-bituminous coal when the total costs per Kwh are tallied up.* Although Nova Scotia coal is calculated to be deliverable at the same cost as U.S. coal, it is not likely to be available since Nova Scotia power plants are expected to absorb all of the thermal coal produced in the province.** Until very recently it appeared that Saskatchewan lignite would be cheap enough to compete as a fuel for some of the longer term coal-fired additions to Ontario Hydro's system.*** However, in September 1978, Saskatchewan increased coal royalties to 15 percent of the mine-head value from 5¢ per ton (1 to 2 percent) previously, thus eroding its competitiveness.****

Ontario does have a lignite deposit of its own at Onakawana which is currently being studied as a fuel source for a mine-mouth thermal generating plant of almost 1000 MW. About 5 million tons of lignite would be mined annually to fuel the plant.***** At an approximate heating value of 5,000 Btu/lb., this translates into an annual energy requirement of 50×10^{12} Btu. While the project would not be required until after 1990, the province's deputy energy minister has recently expressed optimisim that the project will be approved.******

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* *See section 7.0. Nova Scotian coal production costs are also artificially low at present because Devco, the major provincial producer, is subsidized by the federal government.*

** *Matthew, op.cit., slide 4.*

*** *Matthew, op.cit., p. 19.*

**** *Financial Post, October 14, 1978, p. 42.*

***** *The Coal Miner, December 1977, p. 20.*

****** *Financial Post, October 14, 1978, p. 42.*

In summary, primary coal demand is forecast to reach 538 x 10^{12}Btu by the year 2000, given Ontario Hydro's current generation programme. It is expected that at least 90 x 10^{12} Btu will be derived from Canadian sources, rising to 140 x 10^{12}Btu if the Onakawana project is approved. Although U.S. coal is currently foreseen as a cheaper fuel than Canadian coal, both the availability and cost of U.S. coal are major uncertainties over the longer term to the year 2000. Assuming, as Table 101 implies, that U.S. coal imports will at least be maintained at their 1990 level (286 x 10^{12}Btu), Canadian coal could capture anywhere from about 91 to 250 x 10^{12}Btu of Ontario Hydro's thermal electric coal requirements by the end of the forecast period.

Interim Recommendations of the Porter Commission

While the Porter Commission report does not dispute the cost advantages of nuclear plants over alternate technologies for base load generation, it does not endorse the exclusive use of nuclear plants for this purpose, mainly on the grounds that such a system lacks the diversity and flexibility that is desirable.* "A major accident or terrorist incident at an Ontario Hydro nuclear station or indeed at any nuclear station in the world could result in at least a temporary shutdown of all of Ontario's nuclear capacity".** Other sources of concern about such a programme relate to the strain placed upon public capital availability by the high capital requirements of nuclear plants and to obtaining sufficient fuel without resorting to advanced CANDU fuel cycles, an alternative not favoured by the Commission.

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* *Consultants for the Commission concluded that for base-load power generation, nuclear stations had a substantial life cycle cost advantage over coal-fired stations, under a realistic range of assumptions pertaining to discount rates, capacity factors, relative capital costs, and fuel esclation rates (Royal Commission on Electric Power Planning, op.cit., p. 119).*

** *Ibid., p. 179.*

In view of these concerns the Commission proposes that future base load additions (after the last currently-committed base load plant is completed in 1988) should also include a mix of non-nuclear options. Over the period 1988-2000, the 4 percent annual growth rate considered most likely by the Commission would require in the order of 13,600 MW of additional base load capacity. The Commission concludes that nuclear capacity should be limited to a maximum of 3 stations, totalling 10,200 MW, with the remaining 3,400 MW derived from a combination of hydraulic, coal and biomass sources.

If, as recommended by the Commission, a minimum of 1,500 MW of the 3,400 MW requirement is supplied by wood-fuelled electric power, 1,900 MW would remain to be supplied from coal and hydraulic sources.* Should this residual quantity be entirely supplied by coal, in excess of 107 x 10^{12}Btu of fuel would be required annually.** Because of the Porter Commission's lower load growth forecast however total coal use by 2000 would still be less than the forecast of 538 x 10^{12} Btu made by Ontario Hydro.

Ontario Hydro's estimate of coal demand of 538 x 10^{12} Btu by 2000 is viewed as a maximum for 2 reasons. First, it is not considered likely that the government will opt for the most costly coal-fired base load generation suggested by Porter, especially since the province is already heavily committed to a program based upon nuclear power. Second, if Ontario Hydro's load forecast of 5.3 percent per annum is too high, as the Porter Commission contends, the forecast of coal requirements shown in Table 101 is also on the high side. Hence, total coal use is forecast not to exceed 538 x 10^{12}Btu, with Canadian coal use in the range of 91 to 250 x 10^{12}Btu as noted earlier.

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* *Ibid.*

** *Based upon 70% ACF and 9,200 Btu/KWh for base load generation.*

6.0 QUEBEC

Possessing large hydroelectric resources and lacking any indigenous coal reserves, Quebec has no coal-fired generation capacity at present and is unquestionably the province least likely to develop such capability in the future, even with a projected growth rate of about 6.4 percent per annum from 1976 to 1990.* It is expected that currently committed nuclear capacity (1200-1500 MW) in conjunction with hydroelectric capacity will be able to supply all of Quebec's electrical needs to the end of the century.** While Hydro-Quebec is studying the use of coal in the production of electricity as a long-term possibility, Quebec's current energy policy document forecasts that to the year 2000, coal use will continue to be restricted to industrial markets and not be used as a thermal electric fuel.*** Hence, no thermal electric coal use in Quebec is anticipated over the forecast period.

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* *Gouvernement du Québec, Direction générale de l'energie, La politique québécoise de l'energie: Assurer l'avenir, 1978, p. 46.*

** *Ibid., p. 69.*

*** *Ibid.*

7.0 NEW BRUNSWICK, NOVA SCOTIA AND PRINCE EDWARD ISLAND

7.1 Introduction

The three Maritime provinces, which already possess a high degree of interconnection, have agreed to the formation of a Maritime Energy Corporation responsible for planning and developing major generation and transmission projects in the region.* This move was largely prompted by the fact that some of the more attractive future generation options, including nuclear power plants and Fundy tidal installations, were too large to be undertaken by any Maritime province alone. Hence, it seems more appropriate to discuss the potential thermal electric coal requirements of New Brunswick, Nova Scotia, and Prince Edward Island in the same section than in isolation. Discussion is largely restricted to New Brunswick and Nova Scotia, given the very small present load on Prince Edward Island and the likelihood that future load growth will primarily be met from lower cost sources on the mainland.**

7.2 Present and Planned Capacity

A recent study*** has projected that the total capacity of the Maritime Integrated System will increase from 3,177 MW in 1976 to 16,664 MW by the year 2000, implying an average growth rate in excess of 7.1 percent. More current load growth forecasts by the individual utilities, however, show considerably lower rates of growth. The Nova Scotia Power

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* *New Brunswick Electric Power Commission, 1978 Annual Report.*

** *G.J. Protti, Canadian Electric Utility Industry Costs, 1960-1990, Working Paper No. 78-4, Canadian Energy Research Institute, Calgary, Alberta, May 1978.*

*** *Bay of Fundy Tidal Power Review Board, Reassessment of Fundy Tidal Power, November 1977, p. 261, 267.*

Corporation now expects capacity and energy requirements to increase by an average rate of 4.2 percent per annum from 1977 to 2000*, while the New Brunswick Electric Power Corporation forecasts load to grow by about 5 percent per annum over the same time period.

7.3 Projected Coal Requirements

Nova Scotia

In Nova Scotia coal/oil-fired thermal electric plants are presently operating at Trenton and Glace Bay. During 1976 these plants used about 800,000 tons of coal,** of which 90 percent was obtained from Cape Breton. While coal use declined somewhat to 658,000 tons during 1977, it is expected that 1978 use will once again exceed 800,000 tons. An additional 400,000 tons of coal per year will be used when the first 150 MW unit of the mine-mouth Lingan plant on Cape Breton Island is commissioned in 1979, followed by a further 400,000 tons in 1980 when the second Lingan unit comes on-stream.*** By 1985, the Lingan plant could be increased to a total of 600 MW (4 units of 150 MW each), with an associated coal requirement of 1.6 million tons per annum. Total thermal electric coal use in Nova Scotia may thus reach 2.4 million tons per year by 1985.

It is considered unlikely, however, that known coal deposits in Nova Scotia will be able to support more than 600 MW of new generation capacity.**** While an estimated 1.8 billion tons of coal, comprising the majority of the reserves in the province,* exists in the Sydney area, much of it may not be economically accessible because it is located in very thin seams under the ocean. The average delivered cost of coal to the Nova Scotia Power Corporation is currently about \$1.60/million Btu's,** even though the federal government subsidizes coal production costs at the Cape Breton Development Corporation (Devco), which produces about 95 percent of the coal in Nova Scotia. In order to increase coal output at Devco, the feasibility of developing a new mine producing 2 million tons or more per year at Donkin in the Glace Bay area, is presently being studied. Initial estimates are that the mine would coust \$100 million or more, taking 6 to 8 years to begin production following approval.***

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* *Personal communication, Nova Scotia Power Corporation, November 1978.*

** *25.2 million Btu/ton, 8-12% ash, 3 1/2% (maximum) sulphur.*

*** *Personal communication, Nova Scotia Power Corporation, November 1978.*

**** *Bay of Fundy Tidal Power Review Board, op.cit., p. 263.*

Because of the high cost of increasing coal output in Nova Scotia, it is expected that nuclear power will be the cheapest base-load power source once Lingan's 600 MW of coal-fired capacity have been developed in the mid-1980's.**** Thermal electric coal use in Nova Scotia is therefore forecast to increase to 2.4 million tons annually by 1986, remaining constant thereafter.

New Brunswick

In New Brunswick, bituminous coal from the Minto area of the province is currently used in two thermal electric plants - as a primary fuel in the 100 MW Grand Lake plant and as a supplemental fuel in the 35 MW oil/coal plant at Chatham. Total coal requirements of these plants during 1976 were in the order of 230 thousand tons.* With the start-up of a new 200 MW coal/oil burning generating plant at Dalhousie during 1979, a further 300 thousand tons of coal per year will be required,** bringing the total coal use in thermal electric station to more than 500 tons annually. In order to meet this requirement plus smaller amounts of coal used by industrial customers, current New Brunswick productive capacity of 600,000 tons per year will be almost fully utilized. It has been estimated that indigenous New Brunswick coal reserves will be limited to an output of one million tons per year if supplies are to be sustained over the lifetimes of power stations.***

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* *Financial Post, October 28, 1978, p. 16.*

** *Personal communication, Nova Scotia Power Corporation, November 1978.*

*** *Financial Post, op.cit.*

**** *Bay of Fundy Tidal Power Review Board, op.cit.*

With a 630 MW nuclear plant at Pointe Lepreau, due to be commissioned in 1980, no further coal-fired plants have been scheduled over the next decade, although a 200 MW plant at Grand Lake is being considered as a possible later addition. Nevertheless coal use could be increased if a current test program of burning a coal-oil slurry in existing oil-fired boilers proves to be feasible. Slurries of up to 20 percent coal (by energy value) have been burned at the Chatham, N.B. station, although the problem of excessive wear on pump impellors and burner tips has yet to be resolved.**** If the use of such coal slurries is proven to be feasible, existing oil-fired plants could easily absorb the remaining 500 thousand tons per year of potential coal production in the province.*

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* *Statistics Canada, Electric Power Statistics, Volume II, 1976, Catalogue 57-202 Annual.*

** *New Brunswick Power Commission, personal communication, November 1978.*

*** *A.J. O'Conner, "The future of coal in New Brunswick depends on reasonable regulations", Western Miner, October 1978, p. 73.*

**** *O'Conner, op.cit., p. 73.*

On the other hand, coal use within the province could be decreased by the imposition of more stringent sulphur emission standards by the federal government. With the sulphur content of New Brunswick coal averaging 7 percent, expensive flue gas desulphurization equipment would probably need to be installed in coal-fired plants to meet such standards. In this event it would be uneconomic to burn New Brunswick coal as a fuel.**

In view of the economic problems facing the Maritimes, however, such a move by the federal government is not considered likely, particularly since the New Brunswick Electric Power Commission has expressed a desire to maximize the use of indigenous coal resources to achieve a higher level of energy self-sufficiency.*** Total use of New Brunswick coal for thermal electric generation is therefore forecast to increase from 500 thousand tons during 1979 to one million tons per annum by 1990, remaining constant at that level throughout the forecast period. Future base load capacity will likely be provided by the installation of a second unit at the Point Lepreau station which has been designed to accommodate 2 units.****

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* *On the basis of a 80% ACF, this capacity would require 850 thousand tons of coal per annum to provide 20% of the heat requirements at a rate of 10,000 Btu/Kwh, and a thermal value of 11,800 Btu/lb. of coal. Oil-fired plants will likely be run at reduced capacities once nuclear power becomes available, but even at a 50% ACP, about 530,000 tons of coal would be required annually if all existing oil-fired plants were to derive 20% of their fuel requirements from coal.*

** *O'Conner, op.cit., pp. 72-73.*

*** *O'Conner, op.cit., p. 73.*

**** *Protti, op.cit., p. 190.*

7.2 Impact of Tidal Power on Forecast Coal Requirements

The Fundy Tidal Power Review Board concluded that tidal power was economically viable in relation to other generation alternatives and recommended the initiation of a study "to complete detailed investigations and definitive designs, including detailed specifications, for a single basin tidal power development at Site A8 in Cumberland Basin.* This study would be completed in 1981, with actual construction of the project estimated to take an additional 7 years if approved.** Hence, tidal power is unlikely to be available much before 1990.

If constructed, the project would displace about 3 million barrels of oil and 380 thousand tons of coal annually, mainly in the Maritime Integrated System.*** This forecast, however, assumes that in 1990, 5.5 million barrels of oil will continue to be used for power generation. Given the goal of maximizing regional energy self-sufficiency in the Maritimes, one would logically expect further reductions in imported oil before coal use was reduced, particularly in view of the promising prospects for using a coal-oil slurry in conventional oil-fired plants. Taking into account this consideration, as well as the fact that the development of tidal power is still far from being a certainty, no reduction is made to the thermal electric coal requirements forecasts earlier in this section.

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* *Bay of Fundy Tidal Power Review Board, op.cit., p. 11.*

** *Ibid., p. 5, 10.*

*** *Bay of Fundy Tidal Power Review Board, op.cit., p. 301.*

8.0 NEWFOUNDLAND - LABRADOR

During 1976, Newfoundland generated about 41 terawatt-hours (Twh) of electric energy, while requiring only about 7.5 Twh in-province loads.* In spite of this enormous surplus, a substantial portion of electrical requirements on the island of Newfoundland continues to be generated from expensive imported oil.** This paradoxical situation arose during the era of cheap oil when Newfoundland contracted to provide virtually the entire output of the 5225 MW Churchill Falls project to Quebec at rates which appear very cheap in comparison to the cost of current alternatives. With the rise in oil prices, Newfoundland attempted to negotiate the recall of sufficient power (800 MW) to economically justify the building of a transmission line and tunnel from Labrador to the Island.*** However, a stalemate resulted when Quebec demanded compensation equivalent to the marginal cost of generating replacement power in its own system - about ten times more than the rate paid by Hydro Quebec for Churchill Falls power.****

As a result of recent developments, however, it now appears quite likely that Newfoundland will be able to proceed with proposed transmission line. During the First Ministers conference in February, 1978, a 1700 MW hydroelectric project at Gull Island, Labrador was endorsed by the premiers as a project worthy of "accelerated consideration".* A Lower Churchill Development Corporation was subsequently established and is now carrying out detailed feasibility studies of the Gull Island project and a second hydro project at Muskrat Falls, about 40 miles downstream from Gull Island. The Newfoundland and federal governments are reportedly now very close to an agreement to proceed with the Gull Island project, which would be in-service by 1986.** The combined output of these projects would be in the order of 15,000 gigawatt-hours annually.

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* *Statistics Canada, Catalogue 57-204, Electric Power Statistics, Volume 1, 1977.*

** *Reportedly, about 40% of electrical requirements on the island are generated from imported oil (Financial Post, Dec. 3, 1977, p. 1).*

*** *Protti, op.cit., p. 169.*

**** *Ibid., p. 169.*

Current growth forecasts for the Island of Newfoundland call for an increase of 4.5 to 5 percent per annum over the next 20 years. At a 4.5 percent per annum increase, current Island energy requirements of about 5,000 Gwh in 1978 would increase to about 13,000 Gwh by 2000. Hence, it may be seen that the combined output of the aforementioned projects could easily not only supply the incremental energy requirement but also displace fuel oil use in electric generation. On this basis, it is concluded that coal will not be used for thermal electric generation in Newfoundland over the forecast period.

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* *Financial Post, Feb. 25, 1978.*

** *Toronto Globe and Mail, Nov. 17, 1978, personal communication, Newfoundland and Labrador Hydro, January 1979.*

9.0 SUMMARY OF PROJECTED THERMAL ELECTRIC REQUIREMENTS

Based upon the preceding discussion of thermal electric coal requirements on a province-by-province basis, the projected range of requirements of 5 year intervals over the forecast period is summarized in Table 102. While the forecast coal demand is shown in tons as well as Btu's, in some cases the actual tonnage used could vary considerably if a different grade of coal is used than the one anticipated. In Ontario, for example, new thermal electric plants could use lignite with less than half the Btu/ton value of American bituminous coal shown in the table. All coal requirements shown in Table 102, except those of Ontario, are forecast to be derived from Canadian sources. The total coal requirement by the year 2000, is seen to range from 1343-1560 trillion Btu's, with the upper bound about 16 percent greater than the lower bound. A much greater variability (42 percent) is evident in the forecast range of Canadian coal requirements, largely as a result of the uncertainty of future Ontario supply sources.

TABLE 102: SUMMARY OF PROJECTED THERMAL ELECTRIC COAL REQUIREMENTS, 1977-2000

Province	1977(1)	1980	1985	1990	1995	2000
			(Million Tons)			
British Columbia	-	-	-	2.9-11.9	2.9-11.9	2.9-11.9
Alberta	8.4(2)	11.5	17.5	23.0	28.3	36.8
Saskatchewan	4.7	7.0	8.1-8.6	9.9-11.0	11.8-13.9	7.5-17.5
Manitoba	1.2	0.3	0.3	0.3	0.3- 1.8	0.3- 1.8
Ontario - Total	9.7(3)	13.7	14.5	14.5	15.0	20.7
- Canadian Coal	(.23)	(2.7)	(3.5)	(3.5)	(3.5- 4.0)	(3.5- 9.7)
Quebec	-	-	-	-	-	-
New Brunswick	0.2(4)	0.5	0.8	1.0	1.0	1.0
Nova Scotia	0.7(5)	1.6	2.4	2.4	2.4	2.4
Newfoundland	-	-	-	-	-	-
Total, All Sources	24.9	34.6	43.6	54.0-64.1	61.7-74.3	71.6-92.1
Total Canadian Coal	15.4	23.6	32.6	43.0-53.1	50.2-63.3	54.4-81.1
			(Trillion Btu)			
British Columbia	-	-	-	45-130	45-130	45-130
Alberta	134	184	280	368	453	589
Saskatchewan	62	77	84-95	109-121	129-153	83-193
Manitoba	18	4	4	4	4-26	4-26
Ontario - Total	253	356	377	377	390	538
- Canadian Coal	(6)	(70)	(91)	(91)	(91-104)	(91-250)
Quebec	-	-	-	-	-	-
New Brunswick	5	12	18	24	24	24
Nova Scotia	17	40	60	60	60	60
Newfoundland	-	-	-	-	-	-
Total, All Sources	489	673	828-834	987-1084	1105-1236	1343-1560
Total Canadian Coal	242	387	542-548	701-798	806-950	896-1272

(1) *1977 figures are from Statistics Canada, Catalogue 57-003, except as noted below.*

(2) *Energy Resources Conservation Board.*

(3) *Tonnage is expressed in terms of Tons of 26 million Btu's (Matthew, op.cit.) rather than the actual tonnage.*

(4) *New Brunswick Electric Power Commission.*

(5) *Nova Scotia Energy Council, Nova Scotia Energy Perspectives 1978.*

CHAPTER VI

COAL TRANSPORTATION

Developing useful background material for generally applicable determination of coal transportation costs is a relatively challenging task. There are two primary factors underlying this challenge. First, when thinking in terms of Canadian industrial coal markets there a large number of known coal deposits, possibly supplemented by a number of yet unrecognized deposits. There are also a large number of potential market sites. Taking into account all potential coal sources and consumption points there are thousands of potential coal routings, each with a unique transportation cost; or often, with several unique transportation costs based on modal choice, with minimization of cost dependent on volume.

A second factor which must be recognized in a discussion of coal transportation costs is that costs on yet non operational routings are speculative. While to a certain extent it may be possible to explain actual transportation charges on operational routings, it is impossible to predict charges on new routings with a high degree of certainty. The following discussion assumes a reasonable relationship between present coal and bulk commodity transportation costs and future coal transportation costs on similar routings.

In order to provide general applicability and prevent an unreasonable level of complexity, the following strategy is adopted in this transportation discussion and the subsequent chapter in which mine site net back prices are calculated:

(i) consideration is given to four coal types which, in terms of location and thermal quality are believed to be generally representative of the bulk of Canadian coal reserves*;

(ii) industrial markets as assessed in Chapter IV are categorized on a provincial or sub-provincial basis in order to identify aggregate demand at an assumed location which for transportation cost purposes is relatively typical of the whole provincial or sub-provincial region;

(iii) transportation costs are developed for each transportation mode or service, and for various distance ranges and annual volume levels. Costs are presented on a dollars per million Btu's basis for each potential component of the transportation process between any of the four coal source locations and any potential market. In order to determine total transportation costs, the costs for appropriate components are added.

This strategy allows one to work back from the prices at which coal is forecast to be able to penetrate various industrial markets in order to determine net-backs to coal mines at the four representative mine locations.

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* *Consideration is not given to coal deposits which are unique in terms of location; for example, the Onakawana deposit in Ontario and the Hat Creek and Quinsam River deposits in British Columbia. It is anticipated that, if developed, these deposits would serve relatively local markets. Detailed analysis would be required to assess the market on the basis of industrial activity or potential industrial activity near each of these specific deposits.*

Representative source locations used in the transportation cost analysis are identified in Table 103. These are not intended to identify specific deposits, but to be representative of major coal types which could be available in large volumes in the general area of the specific location. Thermal values for two of the locations are based on reported specifications for Ontario Hydro purchases from these areas.* The estimated thermal value for Drumheller coal is based on the subbituminous C ranking of surface mineable coal reserves in this general area of the plains coal region, and for Nova Scotia the thermal value is based on discussion with a representative of the Cape Breton Development Corporation.

TABLE 103: REPRESENTATIVE CANADIAN THERMAL COALS BY SOURCE AND THERMAL VALUE

Location	Thermal Value (MM Btu's/ton)
Cape Breton	25.0
Coalspur(1)	22.0
Drumheller	16.0
Bienfait(2)	14.4

SOURCE: Canadian Resourcecon Limited.

(1) Approximately 40 miles south west of Edson, Alberta.

(2) Near Estevan, Saskatchewan.

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* *E.G. Bazeley, "A Supply System for Western Canadian Thermal Coal", Ontario Hydro, April 1977.*

** *Alberta Energy Resources Conservation Board, "Reserves of Coal, Province of Alberta", December 1976.*

1.0 RAILWAYS

Railways will be an important element in the transportation process for moving thermal coals to Canadian industrial markets. For longer overland hauls (over 150 to 200 miles) railways will have a captive market. For shorter distances they will face competition from the trucking sector, but there is little doubt that they will capture some of the market.

Establishing a nationally applicable procedure for forecasting railway coal tariffs is not an easy matter. A lower limit for any tariff will generally be based upon the incremental costs incurred by the railway in connection with the movement to which the tariff applies. But, a constant relationship between this lower limit and actual tariffs cannot be expected. For a bulk commodity like coal the actual tariff will effectively be limited by: competition from trucks on shorter distance routings; and for longer routings, the difference between the price at which coal can caputre a market and the railway's judgement as to the mimimum mine-site coal price at which a mine will be able to achieve a stable operation. Within this frameweok there is a requirement for reasonable consistency of tariffs. One would not expect large differences in tariffs in situations of similar volume, distance, terrain, railway congestion, etc., simply because of differences in mine site and marketing economics. Thus, existing tariffs for operational coal routings could be expected to exert a reasonable degree of influence on future tariff levels.

The approach used to forecast rail tariffs in this study is based on observed tariffs and costs per ton-mile. Discussion with railway representatives made it clear that "there's more to it than distance", but these discussions failed to establish any better approach. Certainly for a specific proposed routing one could develop speculative background information on incremental costs to the railway, modal competition, mining costs, and the market price at which coal would be competitive. Such information would be an adequate basis for deep discussion between the railway and the shipper, and with due regard for existing tariffs, it would be a reasonable basis for judgement as to an appropriate tariff level. For general, national applicability, however, there appears to be no alternative to the rather pragmatic approach of assuming coal tariffs relate to distance, and future coal tariffs will relate to existing coal tariff levels.

In addition to relating tariffs to distance, consideration must also be given to annual volumes and railway operating procedures on specific coal routings. Several levels of operation are suggested as justifying separate consideration:

- rotary dumping unit trains
- hopper type coal trains
- car blocks
- car-lots

For similar distances tariffs will vary radically between fully utilized unit trains for which the shippers commit to transport large threshold volumes, and single car-lots which can be moved without any commitment to future shipments.

Tariffs for rotary dumping unit train coal routings are outlined in Table 104. In addition an "estimated service value" is indicated in which a 2.0 percent allowance is made for detention charges (for excess terminal time); and in the cases of movements from Winniandy and to Thunder Bay, allowance is made for the values of cars and train sets respectively, as this equipment is not supplied by the railways and its value is therefore not reflected in the tariff.*

Unit train costs calculated on the basis of estimated service value are shown to vary between 1.39 and 1.75 cents per ton-mile. Only the two movements to Thunder Bay involve thermal coal. It is suggested that the lower market value of thermal coal relative to metallurgical coal is a more significant factor in the lower costs per ton-mile than is the routing or the greater haul distance. Table 105 provides an illustrative example of two hypothetical coal tariff strategies over a range of haul distances. The strategies may be considered as representing extremes. With tariffs based on constant cost in terms of cents per ton-mile, revenue per train drops in direct proportion to the reduction in mileage per year. Thus the strategy would only be reasonable if all costs reflected by the tariff were related to operating distance (fuel, rolling stock maintenance, etc.); it would not reflect the capital

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* *Often a shipper or consignee will supply rail cars and in some instances the complete train set. While this strategy may offer a small cost or tax advantage, the difference in total transportation cost would be insignificant in a study of this sort. Thus, all calculations and conclusions are based on the assumption that the full value of locomotives, cars and maintenance is reflected in the (estimated service value) railway tariff.*

TABLE 104: TARIFFS FOR ROTARY DUMPING UNIT TRAIN COAL ROUTINGS

Origin	Destination	Distance (miles)	Tariff ($/ton)	Estimated Service Value ($/ton)	Cost (¢/ton-mile)
Winniandy	North Vancouver	682	10.67 SC	11.91	1.75
Elkview	Roberts Bank	696	11.02	11.24	1.61
Luscar	North Vancouver	703	11.10	11.32	1.61
Coal Valley	Roberts Bank	720 e	12.16	12.40	1.72
Fording	Roberts Bank	728	12.33	12.58	1.69
Corbin	Thunder Bay	1247	16.75 CT	19.20	1.54
Coal Valley	Thunder Bay	1399	16.75 CT	19.44	1.39

SOURCE: Canadian National Railways, "Tariffs W.260, W.1032, W.1034", Canadian Pacific Railways, "Tariffs W.230, 270" (all current as of October 1978).

NOTES: e - estimate, SC - shipper supplied cars, CT - consignee supplied train.

TABLE 105: ILLUSTRATIVE EXAMPLE OF EXTREME STRATEGIES IN COAL UNIT TRAIN TARIFF DETERMINATION

one way distance (miles)	trips per year (1)	mileage per year (000 miles)	indexed mileage per year	constant cost (2)		constant revenue (3)	
				tariff ($/ton)	revenue (000$)	cost ($/ton-mile)	tariff ($/ton)
100	383.6	76.7	0.51	1.45	5,562	2.83	2.83
200	261.4	104.6	0.70	2.90	7,581	2.08	4.16
400	159.7	127.8	0.85	5.80	9,263	1.70	6.80
800	89.8	143.7	0.96	11.60	10,417	1.51	12.08
1200	62.5	150.0	1.00	17.40	10,875	1.45	17.40
1600	47.9	153.3	1.02	23.20	11,113	1.41	22.56
2000	38.8	155.2	1.03	29.00	11,252	1.40	28.00

SOURCE: Canadian Resourcecon Limited.

(1) Trips per year calculated at an average speed of 19 miles per hour plus 12 hours combined loading and unloading time; 360 days per year operation.

(2) Tariffs calculated on the basis of a constant cost per ton-mile of 1.45 cents.

(3) Costs per ton-mile and tariffs calculated on the basis of a constant revenue of $10,875,000 per train per annum.

investment (train, tracks, sidings, signals, etc.). The other extreme in a strategy to set tariffs would be based on constant revenue per train regardless of distance travelled. Capital investment would be reflected but unit distance operating costs would not.

On the basis of actual unit train tariffs and the illustrative example, a cost of 1.45 cents per ton-mile is considered to be a reasonable basis for estimating generally applicable tariffs over most of the range of coal haul distances likely to be encountered in Canada. For hauls of over 600 miles the incremental revenue associated with distance is assumed to provide for mileage related incremental operating costs. For shorter haul distances higher costs per ton-mile are assumed to be necessary to provide an adequate return on capital investment in the unit train operation. Costs per ton-mile, and tariffs are estimated for a range of hauling distances in Table 106, along with costs per million Btu's for the various coal types under consideration. Threshold volumes to justify commitment of a unit train on a full time basis are also shown.

In addition to rotary dumping unit trains there are a number of coal trains operating in western Canada which are comprised of bottom dumping hopper cars.* Tariffs for routings of these trains are listed in Table 107. Costs per ton-mile are somewhat higher than for rotary dumping trains (an average of 0.19 cents per ton-mile). Typically the hopper car trains serve smaller coal mining operations, offering the advantage of a lower threshold volume to justify committed equipment. Trains usually have about 85 cars (sometimes less) and loads are

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* *In some instances the hopper cars would not always constitute the whole train, but the sequence of cars would normally remain unchanged over successive trips.*

TABLE 106: ESTIMATED UNIT TRAIN COAL TARIFFS

distance (miles)	cost (¢/ton-mile)	tariff ($/ton)	threshold volume(1) (000 tons/year)	cost ($/MM Btu's)			
				Cape Breton	Coalspur	Drumheller	Bienfait
100	2.00	2.00	3,836	0.080	0.091	0.125	0.139
200	1.71	3.40	2,610	0.136	0.155	0.213	0.236
300	1.59	4.75	1,980	0.190	0.216	0.297	0.330
400	1.51	6.05	1,590	0.242	0.275	0.378	0.420
500	1.49	7.45	1,330	0.298	0.339	0.466	0.517
600	1.48	8.90	1,150	0.356	0.405	0.556	0.618
700	1.45	10.15	1,000	0.406	0.461	0.634	0.705
800	1.45	11.60	890	0.464	0.527	0.725	0.806
900	1.45	13.05	800	0.522	0.593	0.816	0.906
1000	1.45	14.50	730	0.580	0.659	0.906	1.007
1200	1.45	17.40	620	0.696	0.791	1.088	1.208
1400	1.45	20.30	540	0.812	0.923	1.269	1.410
1600	1.45	23.20	470	0.928	1.055	1.450	1.611
1800	1.45	26.10	420	1.044	1.186	1.631	1.813
2000	1.45	29.00	380	1.160	1.318	1.813	2.014

SOURCE: Canadian Resourcecon Limited

(1) Threshold volume calculated on the basis of 10,000 ton loads; average speed of 19 miles per hour plus 12 hours combined loading and unloading time; 360 days per year operation.

likely to be in the range of 4,500 to 6,500 tons, compared with about 10,000 tons for a unit train. Also, turnaround times are generally longer than for unit trains with significantly greater time allowances for loading and unloading.

TABLE 107: TARIFFS FOR COAL ROUTINGS USING HOPPER CARS

Origin	Destination	Distance (miles)	Tariff ($/ton)	Estimated Service Value ($/ton)	Cost (¢/ton-mile)
Sheernes	Chapelle	532	8.24SC	9.48	1.81
Canmore	Port Moody	560	12.64	12.89	2.30
McGillivray	Port Moody	687	12.02	12.26	1.78
Bienfait	Thunder Bay	703	13.74	14.01	1.99
Coleman	Port Moody	704	12.39	12.65	1.80
Corbin	Thunder Bay	1247	20.95	21.37	1.71
Coal Valley	Thunder Bay	1399	20.95	21.37	1.53
Winniandy	Thunder Bay	1532	22.35	22.80	1.49

SOURCE: Canadian National Railways, "Tariffs W.260, W.1032, W.1034", Canadian Pacific Railways, "Tariffs W.230, 270", (all current as of October, 1978).

Note: SC - some cars supplied by the shipper.

In the future, as movements of coal on Canadian railways increase, it is anticipated that the relative importance of hopper car trains will decline. The highly streamlined operation of unit trains should continue to offer a cost advantage, especially in situations in which new movements would require a complete set of new cars rather than an opportunity to restore or modify old and under utilized hopper cars. As unit trains become more common, opportunities should increase to share train sets on more than one routing, or between two or more shippers. Hopper car trains will still have a role in coal movements but the role is likely to become limited to:

(i) situations in which bottom dumping offers an overall cost advantage (including terminal costs) relative to rotary dumping;

(ii) isolated routings with less than the threshold volume for a unit train, and to which the part time commitment of a unit train would present scheduling and operating problems;

(iii) making-up volumes in excess of the capacity of available unit trains;

(iv) relatively large but irregular shipments of coal to users who purchase on a spot basis.

Generally applicable future tariffs for hopper car coal trains are estimated on the basis of a 20 percent premium over unit train rates (Table 108). This is significantly more than the present average difference between unit trains and hopper car trains, and is intended to reflect an anticipated increasing commitment on the part of the railways to state of the art unit train technology. In certain instances such as isolated coal routings, discretion could reasonably be used in reducing the differential, based on knowledge that annual volume would fully utilize a hopper car train. Threshold volumes would be approximately one-half those shown for unit trains (Table 106) for full time use of a whole train, but could be significantly less in cases where coal cars became the steady base load along a section of a general freight route.

Many potential industrial coal consumption situations would not justify the use of rotary dumping or hopper car coal trains. These would be situations in which the consumer's annual demand would range from a few thousand tons to as

TABLE 108: ESTIMATED HOPPER CAR COAL TRAIN TARIFFS

Distance (miles)	Cost (¢/ton-mile)	Tariff ($/ton)	Cost ($/MM Btu's) Cape Breton	Coalspur	Drumheller	Bienfait
100	2.40	2.40	0.096	0.109	0.150	0.167
200	2.05	4.10	0.164	0.186	0.256	0.285
300	1.91	5.75	0.230	0.261	0.359	0.399
400	1.81	7.25	0.290	0.330	0.453	0.503
500	1.79	8.95	0.358	0.407	0.559	0.622
600	1.78	10.70	0.428	0.486	0.669	0.743
700	1.74	12.20	0.488	0.555	0.763	0.847
800	1.74	13.90	0.556	0.632	0.869	0.965
900	1.74	15.65	0.626	0.711	0.978	1.087
1000	1.74	17.40	0.696	0.791	1.088	1.208
1200	1.74	20.90	0.836	0.950	1.306	1.451
1400	1.74	24.35	0.974	1.107	1.522	1.691
1600	1.74	27.85	1.114	1.266	1.741	1.934
1800	1.74	31.30	1.252	1.423	1.956	2.174
2000	1.74	34.80	1.392	1.582	2.175	2.417

SOURCE: Canadian Resourcecon Limited.

much as a few hundred thousand tons (the latter restricted to locations relatively close to the coal source for which car turnaround time would be quite short). Coal transportation to these consumers would involve single car-lots of coal or blocks of a few (often five) cars which remain as a group for repeated shipments. Generally, small volume coal consumers would incur a significant transportation cost penalty relative to consumers which are able to justify use of coal trains. This penalty might be offset to some extent, by lack of commitment to continuation of coal shipments, allowing flexibility in choice of fuel type, coal source and delivery mode.

Examples of tariffs for car-lot and car-block coal movements, including a number of active routings, are outlined in Table 109. In both cases there is a clear trend for cost per ton-mile to decline as distance increases. A similar situation occurs in "mileage rates" as shown in Table 110. These are applied by the railways on routings for which a specific tariff is not listed for the particular origin/destination.

While both the specified tariffs (Table 109) and the "mileage rates" (Table 110) clearly show the trend of decreasing cost in cents per ton-mile with increasing distance, it is apparent that the specified tariffs are lower than the mileage rates for similar distances. It is assumed that the mileage rates are indicative of a railway strategy for relating revenue to distance; but for situations in which ongoing coal movements are anticipated, a discount from the mileage rates could be expected. For the purpose of calculating coal mine net-backs, estimated generally applicable mileage rates for ongoing movements are outlined in Table 111. These rates are modified from current Eastern mileage rates in Table 110, extended on the basis of the relationship between Eastern

TABLE 109: TARIFFS FOR CAR-LOT AND CAR-BLOCK COAL MOVEMENTS

Origin	Destination	Distance (miles)	Tariff ($/ton)	Cost (¢/ton-mile)	
Car-lots					
Inverness	Trenton	120 e	7.14	5.95	
Bienfait	Brandon	156	12.41	7.96	
Sydney	Brookfield	240 e	9.45	3.94	
Michel	Trail	277	12.78	4.61	
Bienfait	Winnipeg	284	13.68	4.82	
Fording	Trail	306	13.53	4.42	
Sydney	Sackville	317 e	14.01	4.42	
Sydney	Havelock	394 e	10.63	2.70	
Bienfait	Kenora	410	9.26	2.26	
Bienfait	Dryden	493	9.44	1.91	
Luscar	Regina	683	21.77	3.19	
Luscar	Faulkner	1132	28.73	2.54	
Car-blocks					Number of cars
Bienfait	Brandon	156	5.60	3.59	MCP
Michel	Trail	277	10.20	3.68	5
Bienfait	Winnipeg	284	8.86	3.12	MCP
Corbin	Trail	295	10.20	3.46	5
Fording	Trail	306	10.68	3.49	5
Bienfait	Pine Falls	366	8.69	2.37	MCP
Luscar	Flin Flon	917	23.35	2.55	20
Forestburg	Bruce Lake	1087	20.98	1.43	MCP

SOURCE: Canadian National Railways, "Tariffs W.260, 73-5", Canadian Pacific Railways, "Tariff W.230", (all current as of October, 1978).

Note: MCP - multiple carblocks probable.

TABLE 110: COAL MILEAGE RATE TARIFFS

Distance (miles)	Tariff ($/ton) Eastern	Tariff ($/ton) Western	Tariff ($/ton) Michel	Tariff (¢/ton-mile) Eastern	Tariff (¢/ton-mile) Western	Tariff (¢/ton-mile) Michel
50	11.00	11.71	13.36	22.00	23.42	26.72
100	12.45	13.36	14.88	12.45	13.36	14.88
200	14.54	14.88	16.72	6.07	7.44	8.36
300	16.19	16.44	18.80	5.40	5.48	6.27
400	17.35	17.30	20.00	4.34	4.33	5.00
500	18.90	19.08	22.05	3.78	3.82	4.41
600	20.06		23.57	3.34		3.93
700	21.14		25.30	3.03		3.61
800	22.29		26.19	2.79		3.27
900			27.69			3.08
1000			29.14			2.91
1100			30.03			2.73
1200			31.38			2.62
850	22.65		27.09	2.66		3.19

SOURCE: Canadian National Railways, "Tariff 73-5", p. 104A, October 3, 1978; Canadian Pacific Railways, "Tariff W.230", p. 64, 66, August and May, 1978.

NOTE: Michel column is for movements from Michel of Coke, Coke Breeze and Coal Screenings.

TABLE 111: ESTIMATED CAR-LOT TARIFFS

Distance (miles)	Cost (¢/ton-mile)	Tariff ($/ton)	Cost ($/MM Btu's)			
			Cape Breton	Coalspur	Drumheller	Bienfait
50	16.50	8.25	0.330	0.375	0.156	0.573
100	9.35	9.35	0.374	0.425	0.584	0.649
200	5.45	10.90	0.436	0.495	0.681	0.757
300	4.05	12.15	0.486	0.552	0.759	0.844
400	3.25	13.00	0.520	0.591	0.813	0.903
500	2.84	14.20	0.568	0.645	0.888	0.986
600	2.63	15.75	0.630	0.716	0.984	1.094
700	2.48	17.35	0.694	0.789	1.084	1.205
800	2.39	19.10	0.764	0.868	1.194	1.326
900	2.31	20.75	0.830	0.943	1.297	1.441
1000	2.23	22.30	0.892	1.014	1.394	1.549
1100	2.17	23.85	0.954	1.084	1.491	1.656
1200	2.11	25.30	1.012	1.150	1.581	1.757
over 1250	2.05					

SOURCE: Canadian Resourcecon Limited.

and Michel tariffs. The modification involves a 25 percent reduction for distances up to 500 miles, decreasing to no reduction at 1200 miles. Tariffs for car-block movements (Table 112) are estimated on the basis of a further 20 percent reduction from the car-lot tariffs for distances up to 500 miles, decreasing to a five percent reduction for 1200 miles or more.

TABLE 112: ESTIMATED CAR-BLOCK COAL TARIFFS

Distance (miles)	Cost (¢/ton-mile)	Tariff ($/ton)	Cost ($/MM Btu's) Cape Breton	Coalspur	Drumheller	Bienfait
50	13.20	6.60	0.264	0.300	0.413	0.458
100	7.50	7.50	0.300	0.341	0.469	0.521
200	4.35	8.70	0.348	0.395	0.544	0.604
300	3.23	9.70	0.388	0.441	0.606	0.674
400	2.60	10.40	0.416	0.473	0.650	0.722
500	2.27	11.35	0.454	0.516	0.709	0.788
600	2.16	12.95	0.518	0.589	0.809	0.899
700	2.09	14.65	0.586	0.666	0.916	1.017
800	2.06	16.50	0.660	0.750	1.031	1.146
900	2.04	18.40	0.736	0.836	1.150	1.278
1000	2.03	20.25	0.810	0.920	1.266	1.406
1100	2.01	22.15	0.886	1.007	1.384	1.538
1200	2.00	24.05	0.962	1.093	1.503	1.670
over 1200	2.00					

SOURCE: Canadian Resourcecon Limited.

2.0 INTERMODAL TERMINALS

Intermodal transfer terminals on the West Coast, at Thunder Bay, and in the Montreal area may play a role in the movement of coal to industrial markets. Transfer from rail to the marine mode at Thunder Bay would be likely for Western coals moving eastward to southern Ontario and Quebec markets. Alternatively westward rail movement and transfer to ships on the West Coast could provide access to Eastern markets via the Panama Canal and terminal facilities in the Montreal area. In addition to handling Western coal, Montreal area terminals could be required for handling of Nova Scotia coal.

Terminal facilities are in routine operation on the West Coast and at Thunder Bay, and are available and in irregular operation in the Montreal area. For the most part information on coal handling costs is private; though approximate fees are widely known in the coal and transportation industries. Present coal handling fees (or approximations) must be treated with some caution though, as at some terminals significant incremental capacity would require heavy capital investment and higher fees on incremental throughput. In another case an increase in throughput could be expected to result in some reduction in fees. The following discussion is based on communications with spokesmen for terminals, and the railway and shipping industries.

West Coast

Three terminal companies: Neptune Terminals Ltd., Pacific Coast Terminals Ltd., and Westshore Terminals Ltd. presently provide coal transfer facilities at the Port of Vancouver. Costs of routine transfer service, involving sufficient stockpiling to reduce hazards of shipment interruptions, are believed to be in the $1.00 to $1.25 per ton range depending upon the terminal and the particular requirements of the various customers.

It is highly unlikely that coal throughput from Vancouver could be increased significantly without a substantial increase in rates for incremental volumes. Major capital expenditure on ship loading equipment would be required at Neptune, and on both ship loading and train unloading equipment at Pacific Coast. Westshore is seeking approval for an expansion plan at this time, but until approval is received they are constrained from increasing throughput by a lack of land for storage of more than the five types of coal they presently handle. Expansion will require a major program of dredging, land creation, railway loop construction and equipment acquisition. Cost of service on incremental throughput at an expanded facility in the early to mid-1980's is estimated to be about $2.00 per ton (1978$), or almost double the present rate. For the relatively small volumes which might be shipped to Eastern industrial markets, a premium on the incremental capacity rate might be anticipated. Allowing for a 10 percent premium a rate of $2.20 per ton is used in this study. The assumptions are made that volumes consolidated by single contracts will be less than enough for a full time unit train (about 1.0 million tons per annum from Rocky Mountain mines), but sufficient for one or more Panamax bulker size -- St. Lawrence draft shiploads (about 45,000 tons each). Also, the coal would be dispatched from the mine in unit trains or reasonably large car blocks, and the period for receipt by and dispatch from the terminal would not be unduly extended (a maximum of about a month).

Of the Western coal types under consideration only the Coalspur type is likely to be shipped east via the West Coast. Additional railway distance to the Drumheller and Bienfait sources; and higher railway, terminal and shipping costs per unit of energy content, rule out westward movements of these coal types en route to Eastern markets. For the Coalspur coal type a terminal charge of $2.20 per ton equates to $0.100 per million Btu's.

Thunder Bay

Thunder Bay Terminals Ltd. and Valley Camp Ltd. provide lakehead coal transfer facilities. The former facility has come on stream during the past year on the basis of long term handling contracts with Ontario Hydro, while the latter is a multi-commodity bulk facility which has been handling coal since 1904.

With all capital costs incurred during the past few years, and with an ice-restricted shipping season of about eight months, handling costs at Thunder Bay Terminals are relatively high. Actual charges on shipments for Ontario Hydro are not public, but popular opinion is that they are over $3.00 per ton, with some suggestion that they may approach $5.00 per ton. The terminal would incur only minor additional capital cost in doubling throughput from the planned initial level of somewhat less than three million tons per annum. It may be concluded that incremental throughput would actually reduce per unit handling costs. Thus, for the type of service offered by Thunder Bay Terminals, receipt of rotary dumping unit trains and high-speed ship loading, a reasonable handling fee is estimated to be $3.00 per ton, assuming year-round railway receipts and sufficient storage to ship the annual volume during the ice-free season.

The Valley Camp terminal offers a lower handling fee than could be expected at Thunder Bay Terminals, but its service restricted to bottom-dumping cars and it has a lower ship loading speed. The terminal would be suitable for car-block shipments of insufficient annual volume to justify a unit train. The present fee for transfer from hopper cars to lake carriers is reported to be approximately $2.25 per ton. Allowing for seasonal storage on routine shipments, an average fee of $2.60 per ton should cover transfer from rail cars to lake carriers, or to storage and subsequently to lake carriers.

Estimated costs for intermodal transfer of various coal types are summarized in Table 113. In subsequent analysis the Thunder Bay Terminals rates should be used in conjunction with rotary dumping unit train tariffs, and the Valley Camp rates in conjunction with bottom dumping hopper car, car-block, and car-lot tariffs.

TABLE 113: ESTIMATED COSTS FOR INTERMODAL TRANSFER AT THUNDER BAY

Coal type	Thermal value (MM Btu's/ton)	Unit trains ($3.00/ton)	Car-blocks Car-lots ($2.60/ton)
		($/MM Btu's)	
Coalspur	22.0	0.136	0.118
Drumheller	16.0	0.188	0.163
Bienfait	14.4	0.208	0.181

SOURCE: Canadian Resourcecon Limited.

Montreal Area

Coal shipments up the St. Lawrence to the Montreal area have occurred on a sporadic basis during the past few years. Several terminals are capable or fairly easily could become capable of transferring coal from Panamax or other deep sea vessels to lake carriers or rail cars. Generally, draft is limited to the range of about 35 to 40 feet depending on season and the particular dock, but coal cargoes of about 45,000 tons are not unduly constrained.

One example of a terminal with coal handling ability is the Iron Ore Company of Canada Ltd. facility at Contrecoeur, about 20 miles downstream from Montreal. Coal may be transferred directly from ship to ship or rail car, or may be unloaded to dock or storage for subsequent reloading. Several cargoes have been handled during the past year. Approximate charges are:

	per ton
ship to ship or to rail cars (direct)	$1.60
ship to dock to ship or rail car	$2.10
ship to storage to subsequent reloading	$2.90

Present equipment is considered adequate for handling significantly larger coal volumes than recent movements, and in the event of expansion, no major cost of service increase is foreseen. Allowing for some stockpiling in the case of ongoing coal handling by the terminal, an average charge of $2.50 per ton should cover terminal transfer from deep sea ships to lake carriers or the railway. This equates to $0.115 per million Btu's on Coalspur coal, the only Western coal type under consideration which is likely to be moved via the Panama Canal, or $0.100 per million Btu's for the Nova Scotia coal type.

3.0 SHIP TRANSPORTATION

Consideration is given in this section to the following coal ship routings:

- Thunder Bay to various Great Lakes ports;
- Montreal area to various Great Lakes ports;
- Cape Breton to various St. Lawrence and Great Lakes ports;
- Vancouver area to Montreal area via the Panama Canal.

For the first three routings Great Lakes bulk carriers would be used. It is assumed the maximum vessel size would be 730 feet, allowing passage through locks of the Welland Canal and coal cargoes of a maximum of somewhat more than 30,000 tons. Larger vessels could ultimately be used in Canadian coal trade on the upper Great Lakes, but traffic on the longer-haul routes would have to grow and diversify greatly from anticipated 1980's levels before commissioning of a larger, land-locked vessel would be likely. For the Panama routing ships would be Panamax type* bulk carriers with draft limited to the 35 to 40 feet available at Montreal area terminals. Typical coal loads would be approximately 45,000 tons.

Shipping on the Great Lakes is a highly competitive business in which rates are negotiated privately and are maintained on a confidential basis between shippers and ship owners. Discussion with shipping companies indicated there is a relatively small saving on long term contract rates for very large volumes compared with average spot rates on single loads, though the latter would be subject to seasonal and annual fluctuations depending on bulk commodity traffic levels. Economy of scale is a factor -- rates per ton on a particular route typically would rise if a vessel smaller than the 730 foot maximum size were to be used.

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* *Maximum length of 900 feet, beam of 106 feet and draught of less than 40 feet.*

Two types of vessels are available for coal transport: "bare-backs" which are dependent upon dock-side equipment for unloading, and self-unloaders. All other factors as equal as possible, a self-unloader is estimated to command a premium of about $0.40 per ton. Most coal traffic on the Great Lakes is in self-unloaders, and for the potential industrial uses under consideration in this study the premium on a self-unloader would be more than offset by savings in dock-side handling costs. Thus, the assumption is made that industrial coal traffic would be in self-unloading vessels.

Estimated rates for various generalized Great Lakes and Seaway routings are outlined in Table 114. The basis for the table is a charge of $18,000 per day for steaming and $9,000 per day in port for a vessel with capacity for a 30,000 ton coal load. Allowance is made for return to the shipping port in ballast, as would often be the case for vessels involved in multi-load contracts. A somewhat greater opportunity to avoid a return in ballast in spot charter vessels is likely to be a factor in minimizing the average difference between spot and charter rates. The rates developed on the basis of daily charges on the vessel compare favourable with rates cited or hypothesized by various shipping industry spokesmen. Table 115 provides estimated shipping rates including allowances for tolls and pilotage which would be additional charges to the shipper or consignee.

TABLE 114: ESTIMATED GREAT LAKES - ST. LAWRENCE SHIPPING CHARGES

($/ton)

FROM:		Thunder Bay	Montreal	Cape Breton
TO:	Lake Huron (north)	2.70	6.15	11.55
	Lake Huron (south)	3.30	5.55	10.95
	Lake Erie	4.20	4.65	10.05
	Lake Ontario	5.10	3.75	9.15
	Montreal	8.40	-	5.85

SOURCE: Canadian Resourcecon Limited.

TABLE 115: ESTIMATED GREAT LAKES - ST. LAWRENCE SHIPPING CHARGES INCLUDING TOLLS AND PILOTAGE

($/ton)

FROM:		Thunder Bay	Montreal	Cape Breton
TO:	Lake Huron (north)	2.70	6.65	12.20
	Lake Huron (south)	3.30	6.05	11.60
	Lake Erie	4.20	5.15	10.70
	Lake Ontario	5.35	4.25	9.80
	Montreal	9.15	-	6.00

SOURCE: Canadian Resourcecon Limited.

In addition to shipping charges in the Great Lakes - St. Lawrence area, coal movements from Western Canada via the Panama Canal will bear deep sea shipping charges. These charges could vary widely depending upon the flag of the carrier and the conditions of the shipping contract. At the low end of the range there is likely to be an advantage in shipping via the Panama; however, when charges approach the high end of the range, eastward rail movement is likely to be more attractive.

The Shipping Act stipulates that Canadian ships must be used for movements of goods between Canadian ports. Regulations under the Act allow the Minister of National Revenue to waive this requirement upon advice from the Canadian Transport Commission that no Canadian ship is available for a proposed movement. A few Canadian ships are capable of inter-coastal coal movements, and on at least one occasion in recent years a Canadian ship has been used. During the past year negotiations for spot charter coal rates using foreign vessels have been frustrated by the requirement to obtain the waiver.

Assuming a Canadian shipping company desired an inter-coastal coal movement, in general the rate would be expected to be higher than that offered by foreign carriers. Speculatively, a rate for moving a cargo from Vancouver to Montreal is estimated to be in the \$20 to \$25 per ton range, assuming the westward trip would be made in ballast and allowing for pilotage and canal tolls. In the event of a prearranged cargo rather than ballast for the westward trip, some saving would be expected.

If no Canadian carrier desired a particular coal movement, and a foreign vessel was to be used, the circumstances of the particular contract would be instrumental in determining the rate. Spot rates vary widely depending on shipping demand. For example, from Hampton Roads, Virginia to Tokoyo, spot rates have varied from below \$4 in 1972, to \$25 in late

1974, to $6 in 1976 and $7.50 to $8.50 in 1978.* Contract rates reflect spot rates at the time of negotiation but are highly buffered from the extremes.

The Hampton Roads to Tokoyo coal rate may be used as a basis for estimating a rate for Vancouver to the Montreal area. While the Vancouver to Montreal route is shorter (7,336 versus 9,504 nautical miles), part of the approximately one week difference in one-way shipping time would be offset by the extra unloading time requirement in the Montreal area relative to a Japanese port. Making allowance for a somewhat shorter ship-time requirement, relative value of the Canadian dollar, and short rather than long tons, a reasonable shipping rate for Vancouver to Montreal area movements (Canadian dollars per short ton) is estimated to be 90 percent of the Hampton Roads to Tokoyo rate (U.S. dollars per long ton).**

Based on the 90 percent relationship and spot rates as outlined above, spot rates for coal movements from Vancouver to the Montreal area could range at least between $3.60 and 22.50 per ton. For the period under consideration in this study, any attempt to forecast spot rates would be unreasonaby speculative. However, the range and pattern of past spot rates provides some guidance for estimating the limits for multi-load contract rates, and these rates will be used for calculating total transportation costs for Western coal moving eastward via the Panama Canal. Depending upon current spot rates and the term and volume invovled in a multi-load contract, a range of $8.50 to $17.00 per ton is estimated for the Vancouver to Montreal area routing. Panama Canal tolls and pilotage fees would add up to approximately 2.50 per ton (assuming ballast on the westward voyage) for total shipping costs of $11.00 to $19.50 per ton.

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* *Seatrade, "Dry cargo voyage freight rates", monthly. Rates are in U.S. dollars per long ton.*

** *85 percent ship-time requirement x 1.176 Canadian dollars per U.S. dollar x 0.893 long tons/short ton.*

Only the Coalspur type of Western coal is likely to be shipped to Eastern markets via the Panama Canal. Estimated deep sea shipping costs in foreign vessels equate to $0.500 to $0.864 per million Btu's, while for Canadian vessels they would equate to an average of $1.023 per million Btu's. Table 116 summarizes estimated total shipping costs for each coal type under consideration and for each potential routing.

TABLE 116: ESTIMATED SHIPPING COSTS FOR VARIOUS COAL TYPES ON VARIOUS ROUTINGS

($/MM Btu's)

FROM:	Cape Breton	Thunder Bay	Thunder Bay	Thunder Bay	Vancouver		
TYPE:	Cape Breton	Coalspur	Drumheller	Bienfait	Coalspur (1)	Coalspur (2)	Coalspur (3)
TO:							
Lake Huron (north)	0.488	0.123	0.169	0.188	0.802	1.188	1.325
Lake Huron (south)	0.464	0.150	0.206	0.229	0.775	1.161	1.298
Lake Erie	0.428	0.191	0.263	0.292	0.734	1.120	1.257
Lake Ontario	0.392	0.243	0.334	0.372	0.693	1.079	1.216
Montreal	0.240	0.416	0.572	0.635	0.500	0.886	1.023
Atlantic Coast					0.378	0.669	0.773

SOURCE: Canadian Resourcecon Limited.

(1) Foreign vessel, estimated low contract rate.

(2) Foreign vessel, estimated high contract rate.

(3) Canadian vessel at $22.50 per ton.

4.0 TRUCKING

In a number of situations trucking may be the only means, or the most effective means, for moving coal to an industrial consumption point. These will include:

(i) direct delivery from coal mines to nearby industrial sites. Rail access may be available, but for the particular routing and volume situations trucks will offer a lower transportation cost;

(ii) delivery inland from a water to land transfer point; for example, an unloading dock on the Great Lakes. As in the mine to industrial site situation, the particular routing and volume will favour truck over rail, or rail access will not be available.

(iii) delivery from a railway discharge point to a nearby industrial site which lacks rail access.

For situations in which the industrial consumer lacks rail access, the choice of truck is a simple one. Where rail and truck are in competition, the specific circumstances will dictate the choice. In general, distances up to about 50 miles appear to be most effectively served by truck, but favourable railway alignment, siding locations and volume, and a steady flow could reduce this distance. Alternatively, an indirect rail routing and irregular flows could extend the trucking distance to over 150 miles -- the distance a driver could cover on a round-trip basis on a single shift.

While details of provincial weight restrictions differ, coal loads of 35 to 40 tons could be carried for reasonable periods of the year on most Canadian highways. At the present time there is no provision for significantly larger loads, except on private industrial roads. The following discussion is based on the assumption of 35 ton loads. It should, however, be noted that significant economy might be gained in certain instances through revision of weight restrictions, licencing fees, etc. to allow for larger loads on roads upon which traffic generally would be limited by the location to transportation to and from the coal-consuming industrial site.

As every coal trucking situation will be unique, it is somewhat difficult to develop a general background of trucking cost information that is applicable to all situations. The strategy adopted here is to describe an "ideal" situation for a range of distances, and then to consider "good, but less than ideal", and "worst-case" situations.

In an ideal situation trucks would be filled from a premeasured single-load hopper. The only circumstance under which such a situation is likely to arise would be direct delivery from a coal mine to a customer. Cost of the loading hopper would generally preclude its use at intermodal transfer points. As it may be assumed the hopper would be mine-site equipment its cost of operation would be included in the price of the coal (i.e. it will be within the calculated net-back), so it is disregarded in calculating transportation cost. Table 117 illustrates trucking costs for various distances with the assumption that each truck in the service would be used for a full daily shift. A truck charge of $50 per hour is used on the basis of discussion with spokesmen for the trucking industry.

TABLE 117: ESTIMATED COAL TRUCKING COSTS FROM A PRE-MEASURING HOPPER LOADER TO AN INDUSTRIAL SITE

	one-way distance (miles)	trips per shift (4) (7.5 hours)	volume per day (tons)	rate ($/ton)	cost ($/MM Btu's) Coal Type			
					Cape Breton	Coalspur	Drumheller	Bienfait
(1)	165	1	35	10.70	0.430	0.486	0.669	0.743
(1)	85	2	70	5.35	0.214	0.243	0.334	0.372
(1)	53	3	105	3.55	0.142	0.161	0.222	0.247
(2)	30	4	140	2.70	0.108	0.123	0.169	0.188
(2)	19	6	210	1.80	0.072	0.082	0.113	0.125
(2)	13.5	8	280	1.35	0.054	0.061	0.084	0.094
(3)	5.7	12	420	0.90	0.036	0.041	0.056	0.063
(3)	2.6	20	700	0.55	0.022	0.025	0.034	0.038

SOURCE: Canadian Resourcecon Limited.

(1) At 45 miles per hour average speed.

(2) At 35 miles per hour average speed.

(3) At 25 miles per hour average speed.

(4) Allows 5 minutes for each loading and unloading.

In a somewhat less ideal, but still desirable coal trucking situation a medium-size (about five cubic yard) front-end loader would be fully utilized loading coal trucks. The problem with this situation is that at least four truck loads must be dispatched each hour to make efficient use of the loader, and the threshold coal volume is rather large: 1,050 tons a day or a minimum of about 260,000 tons of coal a year (based on single shift scheduling). Table 118 illustrates trucking costs for various distances with the assumption of four truck loads per hour. A truck charge of $50 per hour is used, plus $50 per hour for the front-end loader. The latter may be conservative considering the higher capital cost of the loader relative to the trucks.

In a non-ideal coal trucking situation one is likely to be faced with a requirement for loading the coal, and less than full time utilization of the truck fleet and loader. If the transportation requirement is in a large urban area in which there is considerable competition for short-term contract trucking business (gravel, excavation material, etc.), rates outlined in Table 118 should be reasonably applicable, assuming full-shift truck utilization for a number of consecutive days, and reasonable flexibility in scheduling.

The "worst-case" coal trucking situation is likely to occur in small urban areas in which requirements to move relatively large volumes of coal will exceed the capabilities of local trucking businesses. Additional equipment will be required. Coal transportation will not provide full-time utilization, and as there will be no other significant trucking opportunities, the equipment will sit idle when not engaged in hauling coal.

TABLE 118: ESTIMATED COAL TRUCKING COSTS INCLUDING LOADING WITH A FRONT-END LOADER (Four Loadings Per Hour for 1050 tons per shift)

	one-way distance (miles)	trucks in service	trips per truck (4)	rate ($/ton)	Cost ($/MM Btu's)			
					Cape Breton	Coalspur	Drumheller	Bienfait
(1)	163	30	1	11.10	0.444	0.505	0.694	0.771
(1)	79	15	2	5.70	0.228	0.259	0.356	0.396
(1)	51	10	3	3.90	0.156	0.177	0.244	0.271
(2)	22	6	5	2.50	0.100	0.114	0.156	0.174
(3)	6.3	3	10	1.45	0.058	0.066	0.091	0.101

SOURCE: Canadian Resourcecon Limited.

(1) At 45 miles per hour average speed.

(2) At 35 miles per hour average speed.

(3) At 25 miles per hour average speed.

(4) Allows 10 minutes for loading, 5 minutes for unloading.

Faced with acquisition of equipment for coal trucking with the knowledge that it will be under utilized, there are two options. The first is to use maximum size trucks which offer optimal economy of scale, but which will suffer longer periods of non-use. Alternatively, smaller trucks and loaders may be used. The economy of scale will be lost, but periods of non-use will be shorter, or in some cases may be virtually eliminated.

Table 119 outlines costs for loading and trucking various annual volumes of coal over various distances. Consideration is given to use of 35 ton trucks with a five cubic yard loader and to use of 16 ton trucks and a smaller loader. It may be seen that the preferable choice is dependent upon both volume and distance. Trucking costs for various coal types are outlined in Table 120 on the basis of the more attractive cost identified in Table 119 for each distance/volume combination.

TABLE 119: ESTIMATED COAL TRUCKING COSTS INCLUDING LOADING (FULLY COMMITTED EQUIPMENT)

($/ton)

Annual Volume (000 tons):	5,000	10,000		20,000		50,000		100,000	
Truck Size (tons) :	16	16	35	16	35	16	35	16	35
one way distance (miles)									
150	17.34	15.44	15.70	13.87	12.88	12.92	9.68	-	9.12
100	14.00	10.85	14.22	9.90	9.52	9.33	7.45	-	7.26
50	10.68	7.53	11.89	5.96	7.19	5.51	4.37	-	3.81
25	9.48	6.33	11.21	4.76	6.51	4.06	3.69	-	3.13
12	8.38	5.23	10.57	3.66	5.87	2.71	3.05	2.52	2.11
6	8.06	4.91	10.39	3.34	5.69	2.39	2.87	2.20	1.93
3	7.70	4.55	10.19	2.98	5.49	2.03	2.67	1.84	1.73

SOURCE: Canadian Resourcecon Limited.

NOTES:

1. Assumed speeds: 3 and 6 miles at 25 miles per hour, 12 and 25 miles at 35 miles per hour, 50 to 150 miles at 45 miles per hour.
2. Allowance of 0.5 hours per trip for loading and unloading.
3. For 35 ton truck assumed annual fixed cost of $37,500 plus variable cost of $30 per hour; loader fixed cost of $56,500 plus variable cost of $1,500 per 10,000 tons loaded (loader operator included in truck loading time component).
4. For 16 ton truck assumed annual fixed cost of $12,500 plus variable cost of $24 per hour; loader fixed cost of $19,000 plus variable cost of $1,500 per 5,000 tons loaded (loader operator included in truck loading time component.
5. Additional fixed cost for trucks added each time truck hours exceeds a multiple of 3,750 hours per year (double shift operation 250 days per year).

TABLE 120: ESTIMATED COAL TRUCKING COSTS INCLUDING LOADING (FULLY COMMITTED EQUIPMENT)

($/MM Btu's)

Distance (miles)	volume (000 tons/annum)				
	5	10	20	50	100
Cape Breton Coal Type					
150	0.694	0.618	0.516	0.388	0.364
100	0.560	0.434	0.380	0.298	0.290
50	0.428	0.302	0.236	0.174	0.152
25	0.380	0.254	0.190	0.148	0.126
12	0.336	0.210	0.146	0.108	0.084
6	0.322	0.196	0.134	0.096	0.078
3	3.08	0.182	0.120	0.082	0.070
Coalspur Coal Type					
150	0.789	0.702	0.586	0.441	0.414
100	0.636	0.493	0.432	0.339	0.330
50	0.486	0.343	0.268	0.198	0.173
25	0.432	0.289	0.216	0.168	0.143
12	0.382	0.239	0.166	0.123	0.095
6	0.366	0.223	0.152	0.109	0.089
3	0.350	0.207	0.136	0.093	0.080
Drumheller Coal Type					
150	1.084	0.965	0.805	0.605	0.570
100	0.875	0.678	0.595	0.466	0.454
50	0.668	0.471	0.373	0.273	0.238
25	0.593	0.396	0.298	0.231	0.196
12	0.524	0.327	0.229	0.169	0.132
6	0.504	0.307	0.209	0.149	0.121
3	0.481	0.284	0.186	0.127	0.108
Bienfait Coal Type					
150	1.205	1.073	0.896	0.674	0.632
100	0.972	0.753	0.660	0.517	0.503
50	0.743	0.524	0.410	0.302	0.264
25	0.660	0.441	0.330	0.257	0.219
12	0.583	0.365	0.253	0.188	0.146
6	0.559	0.340	0.233	0.167	0.135
3	0.535	0.316	0.208	0.142	0.122

SOURCE: Table 119.

5.0 ALTERNATIVE TRANSPORTATION SYSTEMS

5.1 Slurry Pipelines

Slurry pipelines could be used to transport coal from Alberta to Ontario with one of the following types of systems:

(i) A coal/water system to Thunder Bay with Great Lakes shipping to southern Ontario: the pipeline length would range from 1,100 miles with the origin in the Drumheller area to 1,300 miles with origin in the Coalspur area.

(ii) A coal/water system extending to southern Ontario via the Straits of Mackinac: a pipeline from the Coalspur area to a terminal at Nanticoke would cover a distance of about 2,000 miles, with almost half in the United States.

(iii) A coal/oil system using one line of the Interprovincial Pipeline system to carry both coal and oil.

A single pipeline could be used to carry both thermal and metallurgical coal in batches.

There are no long distance slurry pipelines operating in Canada. Since Shelpac was disbanded there have been no serious studies either. As a result, available cost estimates for Canadian applications are now four to five years out of date. Table 121 shows speculative estimates of capital costs, operating costs and transportation tariffs for coal/water slurry pipelines ranging in length from 1,100 miles to 2,000 miles. The cost

TABLE 121: SLURRY PIPELINE COAL TRANSPORTATION COSTS

1978 dollars

	Throughput - million short tons/year			
	5	10	15	20
Drumheller - Thunder Bay (1100 miles)				
- capital cost, millions	440	670	850	1,020
- operating cost, millions/yr	34	56	75	95
- tariff, \$/ton(1)	20	16	14	12
Coalspur - Thunder Bay (1300 miles)				
- capital cost, millions	510	770	980	1,180
- operating cost, millions/yr	37	61	81	102
- tariff, \$/ton(1)	23	18	15	14
Coalspur - Nanticoke (2000 miles)				
- capital cost, millions	750	1,140	1,440	1,730
- operating cost, millions/yr	48	78	102	127
- tariff, \$/ton(1)	32	25	21	19

SOURCE: Canadian Resourcecon Limited

(1) Excluding gathering costs.

estimates are based on some available 1973-74 cost estimates, with simple adjustments for cost escalation and length of pipeline. Tariffs are based on operating costs and a 15 percent real rate of return on capital, with the pipeline operating continuously at design throughput.

Table 122 shows a comparison of slurry pipeline and unit train transportation costs over common routes. As shown, at least ten million tons per year throughput will be required before a pipeline would become competitive. In addition, the following conditions are necessary to achieve economical pipeline rates:

(i) Supply sources must be fairly close to one another, to hold down gathering costs; similarly, there must be a concentrated market at the other end to avoid rehandling and distribution costs;

(ii) There must be long term commitments on supply and markets, with a fairly fast build-up to design capacity.

At present, the lack of a large enough market is a major constraint on pipeline development.

5.2 Electrical Transmission

Electrical transmission from coal-fired generating plants in western Canada to load centres in southern Ontario is a potential alternative to transportation of thermal-electric coal over a similar route.

One high voltage d-c transmission line (±600 kV) originating in central Alberta would have a capacity to deliver about 2000 MW

TABLE 122: COMPARISON OF SLURRY PIPELINE AND UNIT TRAIN COSTS

$ per short ton (1978 dollars)

	Throughput - million short tons/year		
	5	10	20
Coalspur - Nanticoke (Lake Erie)			
1) Unit train to Thunder Bay plus Great Lakes shipping	27	27	27
2) Slurry pipeline to Nanticoke (1)	34	27	21
3) Slurry pipeline to Thunder Bay plus Great Lakes shipping (1)	32	27	23
Drumheller - Thunder Bay			
1) Unit train	18	18	18
2) Slurry pipeline (1)	22	18	14

(1) Slurry pipeline costs from Table 97, plus $2/ton gathering cost.

to southern Ontario. The equivalent coal delivery would range from 3.3 million tons per year at 40 percent capacity factor to 6.7 million tons per year at 80 percent capacity factor.*

A 2000 MW coal-fired plant in Alberta would displace an equivalent plant in Ontario, figuring that advantages of interconnection of the two systems (a 2-hour shift in peak loads) would approximately offset peak transmission losses. However, about 500 MW of standby capacity would be required in Ontario to make the transmission system equal in dependability to an Ontario coal-fired plant. The capital cost of this transportation alternative would be about $1,100 million (1978 dollars), including an 1800-mile transmission line, converters at each end of the line and 500 MW of standby capacity in Ontario. Assuming utility financing, with a 10 percent real return on capital, the equivalent coal transportation costs would be approximately as follows:

- $43 per ton at 40 percent capacity factor,
- $29 per ton at 60 percent capacity factor,
- $22 per ton at 80 percent capacity factor.

The economics of electrical transmission are highly dependent upon the capacity factor. Ontario Hydro currently plan to use coal-fired plants in an intermediate role, at about 40 percent capacity factor or less (typically operating 12 hours per day, 5 days per week). Electrical transmission would not be economical for this type of use. If Ontario Hydro decide to utilize western coal for base load generation, instead of nuclear, electrical transmission could become economically competitive with coal transportation.

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* *Based on an average calorific value of 20 million Btu per ton.*

CHAPTER VII

COAL MINE NET-BACK ANALYSIS

In this chapter consideration is given to the levels of net-back which would be available to coal mines from various industrial customers at various locations. The term "net-back", as used throughout this report, denotes the maximum price a coal mine could charge FOB minesite in order to be able to capture a particular market, and implicitly all markets offering higher net-backs; providing there were no competing energy types (for example, U.S. coal or alternative Canadian coal) other than the specified "main competing energy types" at the specified forecast prices. The net-back may be calculated as the forecast price of the main competing energy type, less the sum of the estimated required discount to make coal equally (or slightly more) attractive to the industrial user, plus the forecast cost of coal transportation.

Net-back levels may be calculated using forecast alternative energy prices (Chapter III), estimated discount levels (Chapter III) and forecast transportation costs (Chapter VI). In this chapter a net-back calculating technique is illustrated for 1990, and sufficient data is provided to allow immediate substitution of potential demand forecasts for the year 2000. As the prices of alternative energy types are forecast to stablize in real terms in 1990, there will be no difference between 1990 and 2000 net-back levels, but a difference in potential demand reflecting growth and other changes within various industrial sectors.

In addition to outlining calculation of net-back levels this chapter includes an appraisal of total industrial coal demand on both a regional and a sectoral basis, and analysis of demand sensitivity to higher and lower prices for alternative energy types. The appraisal must be considered illustrative, rather than a forecast, as it relies upon unsubstantiated assumptions as to profitable minesite coal prices.

1.0 SUMMARY OF POTENTIAL THERMAL COAL DEMAND

The maximum potential thermal coal demand of Canadian industries in 1990 and 2000, based on technological possibility alone,* is summarized in Tables 123 and 124. These tables stem directly from analysis of industrial sectors as contained in Chapter IV, and are provided for convenience in identifying components of the potential demand in the following analysis.

2.0 CALCULATION OF NET-BACKS

In the following series of tables net-back calculations are outlined to each of the locations of "typical" coal types as identified in Chapter VI. Arrangement of the tables is as follows:

	COAL SOURCE			
DEMAND REGION	Coalspur	Drumheller	Bienfait	Cape Breton
British Columbia	Table 125	Table 132	---	---
Alberta	Table 134	Table 134	Table 134**	---
Saskatchewan	Table 126	Table 132	Table 131	---
Manitoba	Table 127	---	Table 131	---
Ontario	Table 128	---	Table 131	---
Quebec	Table 129	---	Table 131	Table 133
Atlantic	Table 130	---	---	Table 133

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* *The maximum economic potential will be much less and will depend on the forecast prices of alternative fuels (see Tables 135, 136 and 137).*

** *Assumes a low ranking coal source in Alberta rather than the Bienfait area source.*

TABLE 123: POTENTIAL CANADIAN INDUSTRY THERMAL COAL DEMAND, 1990

Discount*	B.C.	Alta.	Sask.	Man.	Ont.	Que.	Atl.	Total	Sector
($/MM Btu's)					(10^{12} Btu's)				
0.10	-	-	-	-	5.0	-	-	5.0	I&S
0.10	-	-	-	-	5.4	2.5	2.1	10.0	CMT
0.10	-	-	-	0.4	1.2	0.4	-	2.0	LIM
0.25	-	-	-	1.8	15.0	15.0	5.0	36.8	P&P
0.30	-	-	8.6	-	-	-	-	8.6	I&S
0.32	4.4	10.1	1.6	2.7	11.6	11.5	0.5	42.4	CMT
0.40	0.2	1.0	-	0.2	5.8	3.3	0.2	10.7	LIM
0.50	-	-	-	7.2	-	-	-	7.2	S&R
0.75	1.5	-	-	-	6.7	3.5	-	11.7	S&R
0.75		-	-	-	14.3	-	-	14.3	I&S
0.75	-	67.0	-	-	-	-	-	67.0	OSD
1.00	-	0.4	0.2	0.3	3.5	5.6	-	10.0	P&P
1.00	-	-	-	-	-	16.0	-	16.0	S&R
1.15	6.0	27.5	0.6	1.7	31.0	17.1	4.1	88.0	CHM
1.25	-	-	13.3	-	-	-	1.7	15.0	POT
1.25	1.0	-	-	-	6.7	3.5	-	11.2	S&R
1.40	-	1.6	1.1	0.5	21.2	25.9	26.8	77.1	P&P
1.50	2.5	8.2	0.9	1.0	11.6	2.7	0.9	27.8	GEN
1.55	7.0	44.5	0.9	2.6	113.0	27.5	4.5	200.0	CHM
1.75	-	-	7.9	-	-	-	-	7.9	POT
2.15	7.8	18.6	4.8	4.9	59.3	32.0	4.1	131.5	GEN

* *Discount as required relative to the main competing energy type for coal to capture the market.*

TABLE 124: POTENTIAL CANADIAN INDUSTRY THERMAL COAL DEMAND, 2000

Discount* ($/MM Btu's)	B.C.	Alta.	Sask.	Man.	Ont.	Que.	Atl.	Total	Sector
					(10^{12}Btu's)				
0.10	-	-	-	-	5.0	-	-	5.0	I&S
0.10	-	-	-	-	5.4	2.5	2.1	10.0	CMT
0.10	-	-	-	0.4	1.2	0.4	-	2.0	LIM
0.25	-	-	-	1.8	15.0	15.0	5.0	36.8	P&P
0.30	-	-	13.0	-	-	-	-	13.0	I&S
0.32	4.3	11.5	1.5	2.7	11.4	11.4	0.8	43.6	CMT
0.40	0.2	1.2	-	0.4	7.4	3.5	0.2	12.9	LIM
0.50	-	-	-	7.6	-	-	-	7.6	S&R
0.75	1.5	-	-	-	6.4	3.5	-	11.4	S&R
0.75	-	-	-	-	24.3	-	-	24.3	I&S
0.75	-	100.5	-	-	-	-	-	100.5	OSD
1.00	-	1.1	0.6	0.8	5.3	9.4	-	17.2	P&P
1.00	-	-	-	-	-	17.2	-	17.2	S&R
1.15	7.6	34.7	0.8	2.1	39.0	21.6	5.2	111.0	CHM
1.25	-	-	16.9	-	-	-	1.9	18.8	POT
1.25	1.0	-	-	-	6.4	3.5	-	10.9	S&R
1.40	-	1.7	1.2	0.6	15.9	21.9	22.6	63.9	P&P
1.50	8.2	25.4	3.4	3.4	41.8	20.7	3.3	106.2	GEN
1.55	7.0	44.5	0.9	2.6	113.0	27.5	4.5	200.0	CHM
1.75	-	-	6.7	-	-	-	-	6.7	POT
2.15	7.8	18.6	4.8	4.9	59.3	32.0	4.1	131.5	GEN

* *Discount as required relative to the main competing energy type for coal to capture the market.*

Net-back calculations are not included for all coal sources to all demand regions. Exclusions include distant movements of low-ranking coal (Bienfait to Atlantic); movement of low-ranking coal to a demand region beyond a higher-ranking coal with a probable similar mining situation (Bienfait, past Drumheller to British Columbia); and moderately distant to distant movement of coal with a probable high mining cost (Cape Breton to regions west of Quebec).

The tables outlining net-back calculations include in a condensed form a substantial amount of information in order to permit the net-back calculation. From Chapter II the main competing energy types and prices are identified for each region. While these are generally applicable, it will be noted that premiums are added to HFO prices to allow for transportation to remote locations which are not served by natural gas. Discretion is used in identification of the approximate locations of demand within each region, as, of course, it is necessary to have a destination in order to calculate a transportation cost. In cases in which there was a lack of knowledge of precise industrial location, major cities or geographic features are identified to allow a reasonable estimate of transportation costs.

Abbreviations are used in the net-back tables to identify sectors and transportation modes:

Industrial sectors

P&P	Pulp and paper	OSD	Oil sands
CMT	Cement	S&R	Smelting and refining
LIM	Lime	POT	Potash
CHM	Chemicals	GEN	General industrial
I&S	Iron and steel		

Railway transportation

UT	Unit train (Table 106)	CL	Car-lot (Table 111)
HT	Hopper car (Table 108)	CB	Car-block (Table 112)

Terminal service

VT	Vancouver area (page 265)	ET	Montreal, East Coast (page 268)
TT	Thunder Bay (Table 113)		

Ship Transportation (Table 116)

Lake carriers, Thunder Bay or Cape Breton to:		Deep sea ship, Vancouver to:	
LN	Lake Huron (north)	DA	Atlantic ports
LS	Lake Huron (south)	DM	St. Lawrence ports
LE	Lake Erie		
LO	Lake Ontario		
LM	Montreal		

Trucking

TM	from mine (Table 117)	TP	part time use (Table 120)
TF	full time use (Table 118)		

An example of a transportation column entry and net-back calculation are outlined below:

EXAMPLE of "Transportation" column entry, Tables 125 to 134:

1400 UT 0.92, TT 0.14, LS 0.15, 100 TP 0.34

- 1400 miles by unit train, \$0.92/MM Btu's
- Thunder Bay unit train terminal, \$0.14/MM Btu's
- Lake carrier to Lake Huron South, \$0.15/MM Btu's
- 100 miles by truck in part time use, \$0.34/MM Btu's

EXAMPLE of net-back calculation:

from the above example total transportation costs are \$1.55/MM Btu's. If HFO is the main competing fuel at \$2.86/MM Btu's and a \$0.10/MM Btu's discount is required for coal's penetration, a net-back of \$2.86 - (\$1.55 + \$0.10) = \$1.21 is available from the particular market component.

While the reader may draw his own conclusions from the net-back tables, and has a basis for experimentation with his own assumptions, a number of observations may aid an initial interpretation. These are arranged on a regional basis below.

2.1 British Columbia

(i) if Coalspur (Alberta foothills) coal cannot capture a British Columbia market, it is unlikely that British Columbia's major reserves or Alberta Crowsnest reserves would capture that market. "Northeast" reserves are farther from main market centres, and transportation costs would be higher. While mining costs have not been studied there is no apparent reason to believe northeast costs would be lower than in the Alberta foothills. Crowsnest and Coalspur reserves are of a similar distance from main market centres, but it is assumed that mountain mining would be more costly than foothills mining;

(ii) there is a reasonable possibility that relatively low ranking Drumheller (Alberta plains) coal could capture B.C. markets which would not provide a sufficient net-back for the higher ranking Coalspur coal type. The situation would be one in which the difference between Coalspur and Drumheller mining costs (foothills versus plains) would offset higher transportation costs resulting from greater distance and greater cost per unit energy per unit distance. The $1.50 per MM Btu's discount General Industrial demand component with truck delivery (Tables 125 and 132) provides an example;

(iii) it is unlikely that low ranking Saskatchewan (Bienfait) lignite could capture any B.C. markets which would not be captured by Coalspur or Drumheller. Mining costs are assumed to be not significantly lower at Bienfait than (surface mined) from the Alberta plains, and the difference would not offset the higher transportation cost resulting from additional distance;

(iv) in British Columbia, as in a number of other regions, there are relatively small* coal deposits which have not been considered. Examples include Quinsam River on Vancouver Island, and Hat Creek near Lillooet. These reserves may have significant potential for local use, but cannot be studied in detail on an individual basis in a broad national study of this sort. Further, they are considered unlikely to have a very significant impact on total industrial coal sales through penetration of large markets which would not be captured by the four typical coal types which are under consideration;

2.2 Alberta

(i) it is not appropriate to use the typical coal type locations for the Alberta market, though the transportation costs developed in Chapter IV may be applied directly or adjusted on the basis of coal's thermal value (e.g. Bienfait transportation costs x 111 percent adjusts a 14.4 MM Btu's per ton rate to a 13 MM Btu's per ton rate for oil sands consumption in Table 134). Rather than using the typical coal locations it is necessary to estimate the distance to a coal reserve which might be mined for each component of potential demand. With respect to the two typical Alberta coal types, Coalspur and Drumheller, it is worth noting that these locations are representative of bands of similar ranking coal running southeast to northeast through the southern half of the province. For easterly or westerly movements outside the province (excepting market components in western Saskatchewan), Coalspur would be representative of the transportation distance from most of Alberta's higher ranking foothills and mountain reserves; Drumheller, of most of the lower ranking plains reserves. By contrast, within Alberta, other reserves are significantly closer to potential demand locations than Coalspur or Drumheller.

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* *"Small" is used in the context of long-term ability to provide for a significant component of total Canadian industrial energy demand.*

2.3 Saskatchewan, Manitoba, Western and Northern Ontario

(i) cross referencing specific potential demand components between Tables 126 to 128 and Tables 131 and 132 indicates that in many cases there are reasonable net-backs (in the sense of what might be estimated as a mine site price which would provide a mining profit) to two or all three of the Western coal sources. The most probable supply source cannot be determined from this study as it depends upon minimization of combined mine-site and transportation costs.

(ii) assuming Drumheller mining costs will be no lower than Bienfait mining costs, Drumheller coal will not capture any market component east of Saskatchewan. Transportation costs from Drumheller to Manitoba would more than offset the lower transportation cost (per unit energy per unit distance) for movement within and beyond Manitoba.

2.4 Eastern Ontario and Quebec

(i) Coalspur coal could be moved eastward as far as Quebec City via rail and the Great Lakes, or westward and via the Panama, with little difference in transportation costs. Using the high contract rate (Table 116) it is slightly less costly to move coal eastward, but low contract or low spot rates would favour the Panama routing. For points east of Quebec City the high contract rate on the Panama routing is advantageous, but regulated use of a Canadian vessel could eliminate this advantage;

(ii) depending on the levels of assumed reasonable net-backs to Coalspur and Bienfait there is (limited) potential for Bienfait coal to capture markets as far east as Montreal (e.g. cement and lime sectors in Table 131);

(iii) U.S. coal could capture market components in Ontario and Quebec. Market components which give less than whatever might be estimated as minimum reasonable net-backs to Coalspur or Cape Breton might provide reasonable net-backs to U.S. sources. Thus an assessment of coal's total market could be low, if only Canadian sources are considered.

TABLE 125: CALCULATION OF NET-BACKS TO COALSPUR AREA COAL MINE FROM VARIOUS COMPONENTS OF POTENTIAL BRITISH COLUMBIA INDUSTRIAL THERMAL COAL MARKET, 1990*

	general industrial	other sectors
Main competing energy type :	gas	HFO
Competing energy price :	\$3.25/MM Btu's	\$2.86/MM Btu's

Sector	Approximate Location	Potential Coal Demand (10^{12}Btu's)	Transportation	Discount ($/MM Btu's)	Net-Back ($/MM Btu's)
CMT	Vancouver	4.0	700 UT 0.46	0.32	2.08
CMT	Kamloops	0.4	450 CB 0.49	0.32	2.05
LIM	Vancouver	0.2	700 CB 0.67	0.40	1.79
S&R	Ashcroft	1.5	500 UT 0.34, 22 TF 0.11	0.75	1.66
CHM	Vancouver	4.0	700 UT 0.46	1.15	1.25
CHM	Vancouver	2.0	700 UT 0.46, 22 TF 0.11	1.15	1.14
S&R	Trail (1)	1.0	300 CB 0.44	1.25	1.17
GEN	Vancouver	1.0	700 CL 0.79	1.50	0.96
GEN	Vancouver	1.0	700 CL 0.79, 22 TF 0.11	1.50	0.85
GEN	various	0.5	500 CL 0.65	1.50	1.10
CHM	Vancouver	4.7	700 UT 0.46	1.55	0.85
CHM	Vancouver	2.3	700 UT 0.46, 22 TF 0.11	1.55	0.74
GEN	Vancouver	3.1	700 CL 0.79	2.15	0.31
GEN	Vancouver	3.1	700 CL 0.79, 22 TF 0.11	2.15	0.20
GEN	various	1.6	500 CL 0.65	2.15	0.45

* *For methodology, explanatory notes and coding refer to page 293.*

(1) Assumes alternative Rocky Mountain coal source, 22 MM Btu's/ton.

TABLE 126: CALCULATION OF NET-BACKS TO COALSPUR AREA COAL MINE FROM VARIOUS COMPONENTS OF POTENTIAL SASKATCHEWAN INDUSTRIAL THERMAL COAL MARKET, 1990*

Main competing energy type : gas
Competing energy price : $2.63/MM Btu's general industrial
$2.48/MM Btu's other sectors

Sector	Approximate Location	Potential Coal Demand (10^{12}Btu's)	Transportation	Discount	Net-back
				($/MM Btu's)	
I&S	Regina	8.6	650 HT 0.52	0.30	1.66
CMT	Regina	1.6	650 CB 0.63	0.32	1.53
P&P	Prince Albert	0.2	500 CL 0.65	1.00	0.83
CHM	Regina	0.6	650 CB 0.63	1.15	0.70
POT	Saskatoon	8.0	480 CB 0.51	1.25	0.72
POT	Esterhazy	5.3	720 CB 0.68	1.25	0.55
P&P	Prince Albert	1.1	500 CB 0.52	1.40	0.56
GEN	Regina	0.9	650 CL 0.75	1.50	0.38
CHM	Regina	0.9	650 CB 0.63	1.55	0.30
POT	Saskatoon	4.7	480 CB 0.51	1.75	0.22
POT	Esterhazy	3.2	720 CB 0.68	1.75	0.05
GEN	Regina	2.0	650 CL 0.75	2.15	-0.27
GEN	Regina	2.0	650 CL 0.75, 6 TF 0.07	2.15	-0.34
GEN	various	0.8	500 CL 0.65	2.15	-0.17

* *For methodology, explanatory notes and coding refer to page 293.*

TABLE 127: CALCULATION OF NET-BACKS TO COALSPUR AREA COAL MINE FROM VARIOUS COMPONENTS OF POTENTIAL MANITOBA INDUSTRIAL THERMAL COAL MARKET, 1990*

Main competing energy type : gas
Competing energy price : $2.78/MM Btu's general industrial
$2.63/MM Btu's other sectors

Sector	Approximate Location	Potential Coal Demand (10^{12} Btu's)	Transportation	Discount ($/MM Btu's)	Net-back ($/MM Btu's)
LIM	Faulkner**	0.4	1100 CB 1.01	0.10	2.00
P&P	Pine Falls, The Pas**	1.8	1030 CB 0.95	0.25	1.91
CMT	Winnipeg	2.7	960 CB 0.89	0.32	1.42
LIM	Faulkner**	0.2	1100 CB 1.01	0.40	1.70
S&R	Flin Flon**	7.2	920 HT 0.73	0.50	1.88
P&P	Pine Falls, The Pas**	0.3	1030 CB 0.95	1.00	1.16
CHM	Brandon	0.7	840 CB 0.78	1.15	0.70
CHM	Winnipeg	1.0	960 CB 0.89	1.15	0.59
P&P	Pine Falls, The Pas**	0.5	1030 CB 0.95	1.40	0.76
GEN	Winnipeg	1.0	960 CL 0.99	1.50	0.29
CHM	Brandon	1.1	840 CB 0.78	1.55	0.30
CHM	Winnipeg	1.5	960 CB 0.89	1.55	0.19
GEN	Winnipeg	2.0	960 CL 0.99	2.15	-0.36
GEN	Winnipeg	2.0	960 CL 0.99, 6 TF 0.07	2.15	-0.43
GEN	various	0.9	850 CL 0.91	2.15	-0.28

* *For methodology, explanatory notes and coding refer to page 293.*

NOTE: HFO price of $3.11/MM Btu's is used for Faulkner, Pine Falls, The Pas, and Flin Flon to reflect additional transportation expense.

TABLE 128: CALCULATION OF NET-BACKS TO COALSPUR AREA COAL MINE FROM VARIOUS COMPONENTS OF POTENTIAL ONTARIO INDUSTRIAL THERMAL COAL MARKET, 1990*

Region :	W	N	S&E	
Main competing energy type :	gas	gas	gas/HFO	
Competing energy price :	2.91	3.10	3.23	($/MM Btu's general industrial)
	2.76	2.95	2.86	($/MM Btu's other sectors)

Sector	Approximate Location	Potential Coal Demand (10^{12}Btu's)	Transportation	Discount ($/MM Btu's)	Net-Back ($/MM Btu's)
I&S	Bruce Lake	5.0	1230 HT 0.97	0.00	2.14
CMT	S. Ont. various	1.4	1400 UT 0.92, TT 0.14, LS 0.15, 100 TP 0.34	0.10	1.21
CMT	E. Ont. various	4.0	1400 UT 0.92, TT 0.14, LO 0.24, 6 TP 0.11	0.10	1.35
LIM	Sault Ste. Marie	0.3	1400 HT 1.11, TT 0.12, LN 0.12, 6 TF 0.07	0.10	1.43
LIM	Kitchener	0.9	1400 HT 1.11, TT 0.12, LS 0.15, 100 TP 0.34	0.10	1.04
P&P	W. Ont. various	5.0	1300 CB 1.18	0.25	1.33
P&P	N. Ontario	2.2	1600 CB 1.45	0.25	1.25
P&P	N.E. Ontario	3.9	1800 CB 1.63	0.25	1.07
P&P	S. Ontario	3.9	1400 HT 1.11, TT 0.12, LO 0.24, 22 TF 0.11	0.25	1.03
CMT	S. Ont. various	2.9	1400 UT 0.92, TT 0.14, LS 0.15, 100 TP 0.34	0.32	0.99
CMT	E. Ont. various	8.7	1400 UT 0.92, TT 0.14, LO 0.24, 6 TF 0.07	0.32	1.17
LIM	Sault Ste. Marie	1.5	1400 HT 1.11, TT 0.12, LN 0.12, 6 TF 0.07	0.40	1.13
LIM	Kitchener	4.3	1400 HT 1.11, TT 0.12, LS 0.15, 100 TP 0.34	0.40	0.74
S&R	N. Ontario	6.7	1900 UT 1.25	0.75	0.95
I&S	N. Ontario	14.3	1900 UT 1.25	0.75	0.95
P&P	W. Ontario	1.2	1300 CB 1.18	1.00	0.58
P&P	N. Ontario	0.5	1600 CB 1.45	1.00	0.50
P&P	N.E. Ontario	0.9	1800 CB 1.63	1.00	0.32
P&P	S. Ontario	0.9	1400 HT 1.11, TT 0.12, LO 0.24, 22 TF 0.11	1.00	0.28
CHM	Sarnia	18.6	1400 UT 0.92, TT 0.14, LS 0.15, 6 TF 0.07	1.15	0.43
CHM	L. Erie various	3.1	1400 HT 1.11, TT 0.12, LE 0.19, 6 TP 0.11	1.15	0.18
CHM	L. Ont. various	9.3	1400 UT 0.92, TT 0.14, LO 0.24, 22 TF 0.11	1.15	0.30
S&R	N. Ontario	6.7	1900 UT 1.25	1.25	0.45
P&P	W. Ontario	7.0	1300 HT 1.03	1.40	0.33
P&P	N. Ontario	3.1	1600 HT 1.27	1.40	0.28
P&P	N.E. Ontario	5.5	1800 HT 1.42	1.40	0.13
P&P	S. Ontario	5.6	1400 UT 0.92, TT 0.14, LO 0.24, 22 TF 0.11	1.40	0.05
GEN	W. Ontario	1.2	1400 CB 1.27	1.50	0.14

* *For methodology, explanatory notes and coding refer to page 293.*

Continued

TABLE 128 (continued)

Sector	Approximate Location	Potential Coal Demand (10^{12} Btu's)	Transportation	Discount ($/MM Btu's)	Net-Back ($/MM Btu's)
GEN	Lake Huron Inld.	3.5	1400 HT 1.11, TT 0.12, LS 0.15, 100 TP 0.34	1.50	0.01
GEN	Lake Ontario	6.9	1400 HT 1.11, TT 0.12, LO 0.24, 6 TF 0.07	1.50	0.19
CHM	Sarnia	67.8	1400 UT 0.92, TT 0.14, LS 0.15, 6 TF 0.07	1.55	0.03
CHM	L. Erie various	11.3	1400 UT 0.92, TT 0.14, LE 0.19, 6 TP 0.11	1.55	-0.05
CHM	L. Ont. various	33.9	1400 UT 0.92, TT 0.14, LO 0.24, 22 TF 0.11	1.55	-0.10
GEN	W. Ontario	5.9	1400 CB 1.27	2.15	-0.51
GEN	Lake Huron Inld.	17.8	1400 HT 1.11, TT 0.12, LS 0.15, 100 TP 0.34	2.15	-0.64
GEN	Lake Ontario	35.6	1400 HT 1.11, TT 0.12, LO 0.24, 6 TF 0.07	2.15	-0.46

NOTE: Net-back calculations require matching of consumption point to regional energy price. HFO price of $3.11/ MM Btu's is used for Bruce Lake to reflect additional transportation expense.

TABLE 129: CALCULATION OF NET BACKS TO COALSPUR AREA COAL MINE FROM VARIOUS COMPONENTS OF POTENTIAL QUEBEC INDUSTRIAL THERMAL COAL MARKETS, 1990*

	general industrial	other sectors
Gas service area		
Main competing energy type :	gas	HFO
Competing energy price :	$3.23/MM Btu's	$2.86/MM Btu's
Gas non-service area		
Main competing energy type :	fuel oil	HFO
Competing energy price :	$3.79/MM Btu's	$2.86/MM Btu's

Sector	Approximate Location	Potential Coal Demand (10^{12} Btu's)	Transportation	Discount ($/MM Btu's)	Net-back ($/MM Btu's)
CMT	Montreal, Quebec	2.5	1400 UT 0.92, TT 0.14, LM 0.42, 22 TF 0.11	0.10	1.17
LIM	Montreal area	0.4	1400 CB 1.27, TT 0.12, LM 0.42, 22 TF 0.11	0.10	0.84
P&P	St. Law. Shore	7.5	1400 UT 0.92, TT 0.14, LM 0.42, 6 TF 0.07	0.25	1.06
P&P	various inland	5.2	1400 UT 0.92, TT 0.14, LM 0.42, 51 TF 0.18	0.25	0.95
P&P	Lac St. Jean	2.3	700 UT 0.46, VT 0.10, DM 0.89, ET 0.10, 3 TP 0.14	0.25	1.07
CMT	Montreal, Quebec	11.5	1400 UT 0.92, TT 0.14, LM 0.42, 22 TF 0.11	0.32	0.95
LIM	Montreal area	3.3	1400 UT 0.92, TT 0.14, LM 0.42, 22 TF 0.11	0.40	0.87
S&R	Noranda	3.5	1800 UT 1.19	0.75	1.07
P&P	St. Law. Shore	2.8	1400 UT 0.92, TT 0.14, LM 0.42, 6 TF 0.07	1.00	0.31
P&P	various inland	2.0	1400 UT 0.92, TT 0.14, LM 0.42, 51 TF 0.18	1.00	0.20
P&P	Lac St. Jean	0.8	700 UT 0.46, VT 0.10, DM 0.89, ET 0.10, 3 TP 0.14	1.00	0.32
S&R	Arvida	16.0	700 UT 0.46, VT 0.10, DM 0.89, ET 0.10	1.00	0.46
CHM	Montreal area	17.1	1400 UT 0.92, TT 0.14, LM 0.42, 6 TF 0.07	1.15	0.16
S&R	Noranda	3.5	1800 UT 1.19	1.25	0.57
P&P	St. Law. Shore	13.0	1400 UT 0.92, TT 0.14, LM 0.42, 6 TF 0.07	1.40	-0.09
P&P	various inland	9.1	1400 UT 0.92, TT 0.14, LM 0.42, 51 TF 0.18	1.40	-0.20
P&P	Lac St. Jean	3.8	700 UT 0.46, VT 0.10, DM 0.89, ET 0.10, 3 TP 0.14	1.40	-0.08
GEN	Montreal	2.2	1400 HT 1.11, TT 0.12, LM 0.42, 22 TF 0.11	1.50	-0.03
GEN	Quebec	0.5	1400 HT 1.11, TT 0.12, LM 0.42, 22 TF 0.11	1.50	0.53
CHM	Montreal area	27.5	1400 UT 0.92, TT 0.14, LM 0.42, 6 TF 0.07	1.55	-0.24
GEN	Montreal	25.6	1400 HT 1.11, TT 0.12, LM 0.42, 22 TF 0.11	2.15	-0.68
GEN	Quebec	6.4	1400 HT 1.11, TT 0.12, LM 0.42, 22 TF 0.11	2.15	-0.12

* *For methodology, explanatory notes and coding refer to page 293.*

NOTE: Net-back calculations require matching of sector and area to energy prices. HFO price of $3.01/MM Btu's used for Arvida, Lac St. Jean and Noranda to reflect additional transportation expense.

TABLE 130: CALCULATION OF NET-BACKS TO COALSPUR AREA COAL MINE FROM VARIOUS COMPONENTS OF POTENTIAL ATLANTIC INDUSTRIAL THERMAL COAL MARKETS, 1990*

Main competing energy type : HFO/FO
Competing energy price : \$3.79/MM Btu's general industrial
\$2.86/MM Btu's other sectors

Sector	Approximate Location	Potential Coal Demand (10^{12}Btu's)	Transportation	Discount ($/MM Btu's)	Net-back ($/MM Btu's)
CMT	various inland	2.1	700 UT 0.46, VT 0.10, DA 0.67, ET 0.10, 75 CB 0.32	0.10	1.11
P&P	various coastal	4.0	700 UT 0.46, VT 0.10, DA 0.67, ET 0.10, 6 TP 0.15	0.25	1.13
P&P	various inland	1.0	700 UT 0.46, VT 0.10, DA 0.67, ET 0.10, 50 TP 0.27	0.25	1.01
CMT	various inland	0.5	700 UT 0.46, VT 0.10, DA 0.67, ET 0.10, 75 CB 0.32	0.32	0.89
LIM	Havelock	0.2	700 UT 0.46, VT 0.10, DA 0.67, ET 0.10, 100 CB 0.34	0.40	0.79
CHM	various coastal	4.1	700 UT 0.46, VT 0.10, DA 0.67, ET 0.10, 6 TF 0.07	1.15	0.31
POT	N.B. inland	1.7	700 UT 0.46, VT 0.10, DA 0.67, ET 0.10, 75 CB 0.32	1.25	-0.04
P&P	various coastal	21.4	700 UT 0.46, VT 0.10, DA 0.67, ET 0.10, 6 TF 0.07	1.40	0.06
P&P	various inland	5.4	700 UT 0.46, VT 0.10, DA 0.67, ET 0.10, 50 TF 0.18	1.40	-0.05
GEN	various coastal	0.9	700 UT 0.46, VT 0.10, DA 0.67, ET 0.10, 6 TF 0.07	1.50	0.89
CHM	various coastal	4.5	700 UT 0.46, VT 0.10, DA 0.67, ET 0.10, 6 TF 0.07	1.55	-0.09
GEN	various coastal	4.1	700 UT 0.46, VT 0.10, DA 0.67, ET 0.10, 6 TF 0.07	2.15	0.24

* *For methodology, explanatory notes and coding refer to page 293.*

TABLE 131: CALCULATION OF NET-BACKS TO BIENFAIT AREA COAL MINE FROM VARIOUS COMPONENTS OF POTENTIAL SASKATCHEWAN, MANITOBA, ONTARIO AND QUEBEC INDUSTRIAL THERMAL COAL MARKET, 1990*

Sector	Approximate Location	Potential Coal Demand 10^{12}Btu's	Transportation	Competing Energy Price(1)	Discount(2) ($/MM Btu's)	Net-back
I&S	Regina	8.6	140 CB 0.55	2.48	0.45	1.48
CMT	Regina	1.6	140 CB 0.55	2.48	0.47	1.46
P&P	Prince Albert	0.2	400 CL 0.90	2.48	1.15	0.43
CHM	Regina	0.6	140 CB 0.55	2.48	1.30	0.63
POT	Saskatoon	8.0	290 CB 0.67	2.48	1.40	0.41
POT	Esterhazy	5.3	210 CB 0.61	2.48	1.40	0.47
P&P	Prince Albert	1.1	400 CB 0.72	2.48	1.55	0.21
GEN	Regina	0.9	140 CB 0.55	2.48	1.65	0.28
CHM	Regina	0.9	140 CB 0.55	2.48	1.70	0.23
POT	Saskatoon	4.7	290 CB 0.67	2.48	1.90	-0.09
POT	Esterbazy	3.2	210 CB 0.61	2.48	1.90	-0.03
GEN	Regina	2.0	140 CB 0.55	2.63	2.30	-0.22
GEN	Regina	2.0	140 CB 0.55, 6 TF 0.10	2.63	2.30	-0.32
GEN	various	0.8	200 CB 0.60	2.63	2.30	-0.27
LIM	Faulkner	0.4	430 CL 0.93	3.11	0.25	1.93
P&P	Pine Falls, The Pas	1.8	460 CB 0.76	3.11	0.40	1.95
CMT	Winnipeg	2.7	290 CB 0.67	2.63	0.47	1.49
LIM	Faulkner	0.2	430 CB 0.74	3.11	0.55	1.82
S&R	Flin Flon	7.2	560 HT 0.69	3.11	0.65	1.77
P&P	Pine Falls, The Pas	0.3	460 CB 0.76	3.11	1.15	1.20
CHM	Brandon	0.7	160 CB 0.57	2.63	1.30	0.76
CHM	Winnipeg	1.0	290 CB 0.67	2.63	1.30	0.66
P&P	Pine Falls, The Pas	0.5	460 CB 0.76	3.11	1.55	0.80
GEN	Winnipeg	1.0	290 CB 0.67	2.78	1.65	0.46
CHM	Brandon	1.1	160 CB 0.57	2.63	1.70	0.36
CHM	Winnipeg	1.5	290 CB 0.67	2.63	1.70	0.26
GEN	Winnipeg	2.0	290 CB 0.67	2.78	2.30	-0.19
GEN	Winnipeg	2.0	290 CB 0.67, 6 TF 0.10	2.78	2.30	-0.29
GEN	various	0.9	190 CB 0.60	2.78	2.30	-0.12
I&S	Bruce Lake	5.0	560 HT 0.69	3.11	0.15	2.27
CMT	S. Ont. various	1.4	700 UT 0.70, TT 0.21, LS 0.23, 100 TP 0.50	2.86	0.25	0.97
CMT	E. Ont. various	4.0	700 UT 0.70, TT 0.21, LS 0.23, 6 TP 0.23	2.86	0.25	1.24
LIM	Sault Ste. Marie	0.3	700 UT 0.70, TT 0.21, LN 0.19, 6 TF 0.10	2.95	0.25	1.50
LIM	Kitchener	0.9	700 UT 0.70, TT 0.21, LS 0.23, 100 TP 0.50	2.86	0.25	0.97
P&P	W. Ont. various	5.0	600 CB 0.90	2.76	0.40	1.46
P&P	N. Ontario	2.2	900 CB 1.28	2.95	0.40	1.27
P&P	N.E. Ontario	3.9	1100 CB 1.54	2.95	0.40	1.01
P&P	S. Ontario	3.9	700 UT 0.70, TT 0.21, LO 0.37, 22 TF 0.17	2.86	0.40	1.01

* *For methodology, explanatory notes and coding see page 293. Note that "Bienfait" column transportation costs from Chapter VI are used rather than "Coalspur" as in previous tables.*

Continued

TABLE 131 (continued)

Sector	Approximate Location	Potential Coal Demand (10^{12} Btu's)	Transportation	Competing Energy Price(1)	Discount(2) ($/MM Btu's)	Net-back
CMT	S. Ont. various	2.9	700 UT 0.70, TT 0.21, LS 0.23, 100 TP 0.50	2.86	0.47	0.75
CMT	E. Ont. various	8.7	700 UT 0.70, TT 0.21, LO 0.32, 6 TF 0.10	2.86	0.47	1.01
LIM	Sault Ste. Marie	1.5	700 UT 0.37, TT 0.21, LN 0.19, 6 TF 0.10	2.95	0.55	1.20
LIM	Kitchener	4.3	700 UT 0.70, TT 0.21, LS 0.23, 100 TP 0.50	2.86	0.55	0.67
S&R	N. Ontario	6.7	1200 UT 1.21	2.95	0.90	0.84
I&S	N. Ontario	14.3	1200 UT 1.21	2.95	0.90	0.84
P&P	W. Ontario	1.2	600 CB 0.90	2.76	1.15	0.71
P&P	N. Ontario	0.5	900 CB 1.28	2.95	1.15	0.52
P&P	N.E. Ontario	0.9	1100 CB 1.54	2.95	1.15	0.26
P&P	S. Ontario	0.9	700 UT 0.70, TT 0.21, LO 0.37, 22 TF 0.17	2.86	1.15	0.26
CHM	Sarnia	18.6	700 UT 0.70, TT 0.21, LS 0.23, 6 TF 0.10	2.86	1.30	0.32
CHM	L. Erie various	3.1	700 UT 0.70, TT 0.21, LE 0.29, 6 TP 0.23	2.86	1.30	0.13
CHM	Ont. various	9.3	700 UT 0.70, TT 0.21, LO 0.37, 22 TF 0.17	2.86	1.30	0.11
S&R	N. Ontario	6.7	1200 UT 1.21	2.95	1.40	0.34
P&P	W. Ontario	7.0	600 HT 0.74	2.76	1.55	0.47
P&P	N. Ontario	3.1	700 HT 0.85	2.95	1.55	0.55
P&P	N.E. Ontario	5.5	1100 HT 1.33	2.95	1.55	0.07
P&P	S. Ontario	5.6	700 UT 0.70, TT 0.21, LO 0.37, 22 TF 0.17	2.86	1.55	-0.14
GEN	W. Ontario	1.2	700 CB 1.02	2.91	1.65	0.24
GEN.	L. Huron Inld.	3.5	700 UT 0.70, TT 0.21, LS 0.23, 100 TP 0.50	3.23	1.65	-0.06
GEN	Lake Ontario	6.9	700 UT 0.70, TT 0.21, LS 0.23, 6 TF 0.10	3.23	1.65	0.34
CHM	Sarnia	67.8	700 UT 0.70, TT 0.21, LS 0.23, 6 TF 0.10	2.86	1.70	-0.08
CHM	L. Erie various	11.3	700 UT 0.70, TT 0.21, LE 0.29, 6 TP 0.23	2.86	1.70	-0.27
CHM	L. Ont. various	33.9	700 UT 0.70, TT 0.21, LO 0.37, 22 TF 0.17	2.86	1.70	-0.29
GEN	W. Ontario	5.9	700 CB 1.02	2.91	2.30	-0.41
GEN	L. Huron Isld.	17.8	700 UT 0.70, TT 0.21, LS 0.23, 100 TP 0.50	3.23	2.30	-0.71
GEN	Lake Ontario	35.6	700 UT 0.70, TT 0.21, LS 0.23, 6 TF 0.10	3.23	2.30	-0.31

Continued

TABLE 131 (continued)

Sector	Approximate Location	Potential Coal Demand (10^{12} Btu's)	Transportation	Competing Energy Price (1)	Discount (2) ($/MM Btu's)	Net-back
CMT	Montreal, Quebec	2.5	UM 1.56, 22 TF 0.17	2.86	0.25	0.88
LIM	Montreal area	0.4	UM 1.56, 22 TF 0.17	2.86	0.25	0.88
P&P	St. Law. Shore	7.5	UM 1.56, 6 TF 0.10	2.86	0.40	0.80
P&P	various inland	5.2	UM 1.56, 51 TF 0.27	2.86	0.40	0.63
P&P	Lac St. Jean	2.3	UL 1.71, 3 TP 0.21	3.01	0.40	0.69
CMT	Montreal, Quebec	11.5	UM 1.56, 22 TF 0.17	2.86	0.47	0.66
LIM	Montreal area	3.3	UM 1.56, 22 TF 0.17	2.86	0.55	0.58
S&R	Noranda	3.5	1100 UT 1.11	3.01	0.90	1.00
P&P	St. Law. Shore	2.8	UM 1.56, 6 TF 0.10	2.86	1.15	0.05
P&P	various inland	2.0	UM 1.56, 51 TF 0.27	2.86	1.15	-0.12
P&P	Lac St. Jean	0.8	UL 1.71, 3 TP 0.14	3.01	1.15	0.01
S&R	Arvida	16.0	UL 1.71	3.01	1.15	0.15
CHM	Montreal area	17.1	UM 1.56, 6 TF 0.10	2.86	1.30	-0.10
S&R	Noranda	3.5	1100 UT 1.11	3.01	1.40	0.50
P&P	St. Law. Shore	13.0	UM 1.56, 6 TF 0.10	2.86	1.55	-0.35
P&P	various inland	9.1	UM 1.56, 51 TF 0.27	2.86	1.55	-0.52
P&P	Lac St. Jean	3.8	UL 1.71, 3 TP 0.14	3.01	1.55	-0.39
GEN	Montreal	2.2	UM 1.56, 22 TF 0.17	3.23	1.65	-0.15
GEN	Quebec	0.5	UM 1.56, 22 TF 0.17	3.79	1.65	0.41
CHM	Montreal	27.5	UM 1.56, 6 TF 0.10	2.86	1.70	-0.50
GEN	Montreal	25.6	UM 1.56, 22 TF 0.17	3.23	2.30	-0.80
GEN	Quebec	6.4	UM 1.56, 22 TF 0.17	3.79	2.30	-0.24

NOTE:

(1) *Premiums are added to HFO prices to reflect transportation costs to Northern Manitoba, Bruce Lake, Noranda, Lac St. Jean and Arvida.*

(2) *All discounts increased $0.15/MM Btu's to reflect higher costs of handling and burning lignite coal relative to bituminous.*

(3) *For Quebec markets unit train, terminal, lake carrier transportation cost abbreviated to UM to St. Lawrence ($1.56/MM Btu's) and UL to Lac St. Jean ($1.71/MM Btu's).*

TABLE 132: CALCULATION OF NET BACKS TO DRUMHELLER AREA COAL MINE FROM VARIOUS COMPONENTS OF POTENTIAL BRITISH COLUMBIA AND SASKATCHEWAN INDUSTRIAL THERMAL COAL MARKET, 1990*

Sector	Approximate Location	Potential Coal Demand (10^{12}Btu's)	Transportation	Competing Energy Price	Discount(1) ($/MM Btu's)	Net-back
CMT	Vancouver	4.0	750 UT 0.68	2.86	0.42	1.76
CMT	Kamloops	0.4	500 CB 0.71	2.86	0.42	1.73
LIM	Vancouver	0.2	750 CB 0.97	2.86	0.50	1.39
S&R	Ashcroft	1.5	550 UT 0.51, 22 TF 0.16	2.86	0.85	1.34
CHM	Vancouver	4.0	750 UT 0.68	2.86	1.25	0.93
CHM	Vancouver	2.0	750 UT 0.68, 22 TF 0.16	2.86	1.25	0.77
S&R	Trail(2)	-	-	-	-	
GEN	Vancouver	1.0	750 CL 1.13	3.25	1.60	0.52
GEN	Vancouver	1.0	750 CL 1.13, 22 TF 0.16	3.25	1.60	0.36
GEN	Vancouver	0.5	550 CL 0.94	3.25	1.60	0.71
CHM	Vancouver	4.7	750 UT 0.68	2.86	1.65	0.53
CHM	Vancouver	2.3	750 UT 0.68, 22 TF 0.16	2.86	1.65	0.37
GEN	Vancouver	3.1	750 CL 1.13	3.25	2.25	-0.13
GEN	Vancouver	3.1	750 CL 1.13, 22 TF 0.16	3.25	2.25	-0.29
GEN	various	1.6	550 CL 0.94	3.25	2.25	0.06
I&S	Regina	8.6	470 CB 0.69	2.48	0.40	1.39
CMT	Regina	1.6	470 CB 0.69	2.48	0.42	1.37
P&P	Prince Albert	0.2	410 CL 0.82	2.48	1.10	0.56
CHM	Regina	0.6	470 CB 0.69	2.48	1.25	0.54
POT	Saskatoon	8.0	320 CB 0.61	2.48	1.35	0.52
POT	Esterhazy	5.3	640 CB 0.85	2.48	1.35	0.28
P&P	Prince Albert	1.1	410 CB 0.66	2.48	1.50	0.32
GEN	Regina	0.9	470 CL 0.87	2.63	1.60	0.16
CHM	Regina	0.9	470 CB 0.69	2.48	1.65	0.14
POT	Saskatoon	4.7	320 CB 0.61	2.48	1.85	0.02
POT	Esterhazy	3.2	640 CB 0.85	2.48	1.85	-0.22
GEN	Regina	2.0	470 CL 0.87	2.63	2.25	-0.49
GEN	Regina	2.0	460 CL 0.87, 6 TF 0.09	2.63	2.25	-0.58
GEN	various	0.8	400 CL 0.81	2.63	2.25	-0.43

* *For methodology, explanatory notes and coding refer to page 293.*

(1) *All discounts increased $0.10/MM Btu's to reflect higher costs of handling and burning sub-bituminous coal relative to bituminous.*

(2) *Market component assumed to be automatically captured as shown in Table 124.*

TABLE 133: CALCULATION OF NET-BACKS TO CAPE BRETON AREA COAL MINE FROM VARIOUS COMPONENTS OF POTENTIAL ATLANTIC AND QUEBEC INDUSTRIAL THERMAL COAL MARKETS, 1990*

Main competing energy type : HFO/FO
Competing energy price : $3.79/MM Btu's general industrial
$2.86/MM Btu's other sectors

Sector	Potential Coal Demand (10^{12} Btu's)	Location	Transportation	Discount	Net-back
				($/MM Btu's)	
CMT	0.3	Cornerbrook	SN 0.12	0.10	2.64
CMT	1.0	Brookfield	240 CB 0.36	0.10	2.40
CMT	0.8	Havelock	400 CB 0.42	0.10	2.34
P&P	0.8	Nfld. coastal	SN 0.12	0.25	2.49
P&P	0.5	Nfld. inland	SN 0.12 200 CB 0.35	0.25	2.14
P&P	1.8	various	450 CB 0.44	0.25	2.17
P&P	1.9	various	300 CB 0.39	0.25	2.22
CMT	0.1	Cornerbrook	SN 0.12	0.32	2.42
CMT	0.2	Brookfield	240 CB 0.36	0.32	2.18
CMT	0.2	Havelock	400 CB 0.42	0.32	2.12
LIM	0.2	Havelock	400 CB 0.42	0.40	2.04
CHM	2.1	Saint John	450 CB 0.44	1.15	1.27
CHM	2.0	Halifax	320 CB 0.39	1.15	1.32
POT	1.7	Sussex	410 CB 0.42	1.25	1.19
P&P	4.3	Nfld. coastal	SN 0.12	1.40	1.34
P&P	2.9	Nlfd. inland	SN 0.12, 200 CB 0.35	1.40	0.99
P&P	9.8	various	450 CB 0.44	1.40	1.02
P&P	9.8	various	300 CB 0.39	1.40	1.07
GEN	0.5	various	410 CL 0.52, 6 TF 0.06	1.50	1.71
GEN	0.4	various	300 CL 0.49, 6 TF 0.06	1.50	1.74
CHM	2.3	Saint John	450 CB 0.44	1.55	0.87
CHM	2.2	Halifax	320 CB 0.39	1.55	0.92
GEN	2.1	various	410 CL 0.52, 6 TF 0.06	2.15	1.06
GEN	2.0	various	300 CL 0.49, 6 TF 0.06	2.15	1.09
CMT	2.5	Montreal,Quebec	LM 0.24, 22 TF 0.10	0.10	2.42
LIM	0.4	Montreal area	LM 0.24, 22 TF 0.10	0.10	2.42
P&P	7.5	St. Law. Shore	LM 0.24, 6 TF 0.06	0.25	2.31
P&P	5.2	various inland	LM 0.24, 51 TF 0.16	0.25	2.21
P&P	2.3	Lac St. Jean	LM 0.24, 3 TP 0.12	0.25	2.40
CMT	11.5	Montreal, Quebec	LM 0.24, 22 TF 0.10	0.32	2.20
LIM	3.3	Montreal area	LM 0.24, 22 TF 0.10	0.40	2.12
P&P	2.8	St. Law. Shore	LM 0.24, 6 TF 0.06	1.00	1.56
P&P	2.0	various inland	LM 0.24, 51 TF 0.16	1.00	1.46
P&P	0.8	Lac St. Jean	LM 0.24, 3 TP 0.12	1.00	1.65
S&R	16.0	Arvida	LM 0.24	1.00	1.77

* *For methodology, explanatory notes and coding see page 293. Note that "Cape Breton" colum transportation costs from Chapter VI are used. For shipping to Newfoundland coast a rate denoted "SN" is estimated as one-half that from Cape Breton to Montreal, or $0.12/MM Btu's.*

Continued

TABLE 133 (continued)

Sector	Potential Coal Demand (10^{12}Btu's)	Location	Transportation	Discount ($/MM Btu's)	Net-back ($/MM Btu's)
CHM	17.1	Montreal area	LM 0.24, 6 TF 0.06	1.15	1.41
P&P	13.0	St. Law. Shore	LM 0.24, 6 TF 0.06	1.40	1.16
P&P	9.1	various inland	LM 0.24, 51 TF 0.16	1.40	1.06
P&P	3.8	Lac St. Jean	LM 0.24, 3 TP 0.12	1.40	1.25
GEN	2.2	Montreal	LM 0.24, 22 TF 0.10	1.50	1.39
GEN	0.5	Quebec	LM 0.24, 22 TF 0.10	1.50	1.95
CHM	27.5	Montreal area	LM 0.24, 6 TF 0.06	1.55	1.01
GEN	25.6	Montreal	LM 0.24, 22 TF 0.10	2.15	0.74
GEN	6.4	Quebec	LM 0.24, 22 TF 0.10	2.15	1.30

NOTE: Net-back calculations require matching of sector and area to energy prices. HFO price of $3.01/MM Btu's used for Arvida, Lac St. Jean to reflect additional transportation expense.

TABLE 134: CALCULATION OF NET-BACKS TO VARIOUS ALBERTA COAL MINES FROM VARIOUS COMPONENTS OF POTENTIAL ALBERTA INDUSTRIAL THERMAL COAL MARKET, 1990*

Main competing energy type : gas
Competing energy price : $2.43/MM Btu's general industrial
$2.28/MM Btu's other sectors

Sector	Approximate Location	Potential Coal Demand (10^{12}Btu's)	Transportation	Discount ($/MM Btu's)	Net-back ($/MM Btu's)
CMT	Edmonton (1)	5.1	30 TM 0.17	0.32	1.79
CMT	Exshaw (2)	5.0	14 TM 0.06	0.32	1.90
LIM	various (2)	1.0	19 TM 0.08	0.40	1.80
OSD	Cold Lake (3)	33.5	300 HT 0.44	0.75	1.09
OSD	unspecified (3)	33.5	300 HT 0.44	0.75	1.09
P&P	various (1)	0.4	150 CL 0.63	1.00	0.65
CHM	various (1)	27.5	100 HT 0.15	1.15	0.98
P&P	various (1)	1.6	150 CB 0.51	1.40	0.37
GEN	Calgary (1)	3.3	85 TM 0.33	1.50	0.60
GEN	Edmonton (1)	3.3	30 TM 0.17	1.50	0.76
GEN	various (1)	1.6	53 TM 0.22	1.50	0.71
CHM	various (1)	44.5	100 HT 0.15	1.55	0.58
GEN	Calgary (1)	7.4	85 TM 0.33	2.15	-0.05
GEN	Edmonton (1)	7.4	30 TM 0.17	2.15	0.11
GEN	various (1)	3.8	53 TM 0.22	2.15	0.06

* *For methodology, explanatory notes and coding refer to page 293.*

(1) *Assumes 16 MM Btu's/ton coal source, Drumheller transportation costs.*

(2) *Assumes 22 MM Btu's/ton coal source, Coalspur transportation costs.*

(3) *Assumes 13 MM Btu's/ton coal source, Bienfait transportation costs x 111 percent, i.e. (14.4 ÷ 13.0) MM Btu's/ton.*

3.0 AGGREGATE COAL DEMAND APPRAISAL

Tables 133 and 134 above detail the maximum extent to which coal could penetrate industrial markets based on technological considerations alone. When economic factors are taken into account these potential volumes will be reduced sharply, unless the prices of competing energy forms in the future are assumed to be extremely high. A forecast of markets which could be economically penetrated under the various market price assumptions (Chapter II) and transportation cost assumptions (Chapter VI) made in this report are developed below. The forecast of economically achievable coal markets is also based on specific assumptions with respect to the minimum mine-site prices at which coal could be profitably produced at the various typical coal supply sources which have been considered; the derivation of such prices are beyond the scope of this study but estimates have nevertheless been made which are thought to be reasonable, though they are generally unsubstantiated. For the purpose of compiling aggregate coal demand the following are assumed to be the minimum FOB mine-site prices at which coal mining operations could supply volumes as required and achieve profitable operations:

	$/ton	$/MM Btu's
Cape Breton	35.00	1.400
Coalspur	20.00	0.909
Drumheller	8.00	0.500
Bienfait	6.00	0.416

In effect the minimum price is likely to be close to the maximum price, for it is unlikely that a mine, or several mines producing similar coal in a local area, could get away with charging substantially higher prices to particular customers simply because those customers faced high prices for alternative energy types or low coal transportation costs relative to other customers of the mine.

The methodology involved in compiling aggregate demand is to test each potential demand component to see if it will provide a net-back equal to or greater than one of the above minimum mine-site prices. As soon as a satisfactory net-back is observed the potential demand is compiled as an actual demand, though it should be noted that supply would not necessarily be from the particular source which gives the initial satisfactory net-back. In many cases one of the other sources could offer the customer a lower delivered price (through minimization of combined mine-site price plus transportation costs). The sequence of testing for the compilation is as follows:

(i) potential demand components for all provinces except Alberta are tested for net-backs to Coalspur. Components with satisfactory net-backs are compiled. The initial test is on the Coalspur source as it is judged that Alberta foothills or mountain coal is the most likely Canadian coal to achieve widespread penetration of thermal markets;

(ii) components with unsatisfactory net-backs above, located in Saskatchewan, Manitoba, Ontario and Quebec, are tested for net-backs to Bienfait;

(iii) components with unsatisfactory net-backs above, located in British Columbia and Saskatchewan are tested for net-backs to Drumheller;

(iv) components with unsatisfactory net-backs above, located in the Atlantic region and Quebec are tested for net-backs to Cape Breton;

(v) Alberta components are tested for net-backs on the basis of assumed source distances (Table 134) and required net-backs as for the typical source locations depending on the thermal quality of the assumed supply.

Potential demand components which do not provide a satisfactory net-back in the above testing would not be captured by coal. Exceptions could occur to the extent that small coal deposits might serve local markets, or delivered U.S. coal would undersell Canadian coal in market components which fail to provide a satisfactory return to any of the tested source locations.

3.1 Regional Aggregate Demand

Aggregate coal demand by region is outlined in Table 135. As stated previously, although demand is allocated to specific sources, it must be recognized that allocations result from the testing methodology rather than necessarily being the most efficient servicing of the market. Total demand is correct, but Coalspur is likely to be overstated and the other sources understated.

3.2 Sectoral Aggregate Demand

Aggregate coal demand by sector is outlined in Table 136. The

TABLE 135: AGGREGATE COAL DEMAND BY REGION, 1990 AND 2000

	Coalspur	Bienfait	Drumheller	Cape Breton	Total	
			(10^{12}Btu's)		10^{12}Btu	10^{6}short** tons
			1990			
British Columbia	14.6	-	4.7	-	19.3	0.97
Alberta	6.0	67.0*	85.7	-	158.7	7.94
Saskatchewan	10.2	6.1	8.0	-	24.3	1.22
Manitoba	12.6	3.2	-	-	15.8	0.79
Ontario	60.7	16.1	-	-	76.8	3.84
Quebec	32.5	3.7	-	38.7	74.9	3.75
Atlantic	7.1	-	-	1.6	8.7	0.44
CANADA	143.7	96.1	98.4	40.3	378.5	18.93
			2000			
British Columbia	19.5	-	4.7	-	24.2	1.21
Alberta	6.9	100.5*	111.5	-	218.9	10.95
Saskatchewan	14.5	8.2	10.1	-	32.8	1.64
Manitoba	13.7	6.1	-	-	19.8	0.99
Ontario	70.6	15.7	-	-	86.3	4.32
Quebec	32.4	3.9	-	48.2	84.5	4.23
Atlantic	7.1	-	-	4.3	11.4	0.57
CANADA	164.7	134.4	126.3	52.5	477.9	23.90

* *Assumes a low ranking subituminous coal from a source other than Bienfait.*

** *Coal demand converted into short tons from Btu using a factor of 20 x 10^{6} Btu/ton. Actual calorific values of alternative coal sources which were studied range from 13 MMBtu/ton for Alberta Plains coal to 25 MMBtu/ton for Cape Breton coal.*

TABLE 136: AGGREGATE COAL DEMAND BY SECTOR, 1990 AND 2000

	Coalspur	Bienfait	Drumheller	Cape Breton	Total	
			(10^{12} Btu's		10^{12} Btu	10^6 sho tons**
			1990			
Pulp and paper	37.1	12.5	0.4	5.6	55.6	2.78
Cement	46.8	-	5.1	0.5	52.4	2.62
Lime	4.5	8.0	-	0.2	12.7	0.64
Chemicals	6.0	2.3	76.7	17.1	102.1	5.11
Iron and steel	27.9	-	-	-	27.9	1.40
Oil sands	-	67.0*	-	-	67.0	3.35
Smelting and refining	19.9	-	-	16.0	35.9	1.80
Potash	-	5.3	8.0	-	13.3	0.67
General industrial	1.5	1.0	8.2	0.9	11.6	0.58
TOTAL	143.7	96.1	98.4	40.3	378.5	18.93
			2000			
Pulp and paper	37.6	11.4	1.1	9.4	59.5	2.98
Cement	48.9	-	5.8	0.8	55.5	2.78
Lime	3.4	9.4	-	0.2	13.0	0.65
Chemicals	7.6	2.9	83.9	21.6	116.0	5.80
Iron and steel	42.3	-	-	-	42.3	2.12
Oil sands	-	100.5*	-	-	100.5	5.03
Smelting and refining	20.0	-	-	17.2	37.2	1.86
Potash	-	6.8	10.1	-	16.9	0.85
General industrial	4.9	3.4	25.4	3.3	37.0	1.85
TOTAL	164.7	134.4	126.3	52.5	477.9	23.90

* *Assumes a low ranking subbituminous coal from a source other than Bienfait.*

** *Coal demand converted into short tons from Btu using a factor of 20 x 10^6 Btu/ton. Actual calorific values of alternative coal sources which were studied range from 13 MMBtu/ton for Alberta Plains coal to 25 MMBtu/ton for Cape Breton coal.*

same provision as noted above is applicable to the sectoral aggregation.

4.0 SENSITIVITY OF AGGREGATE COAL DEMAND TO ALTERNATIVE ENERGY TYPE PRICES

Sensitivity of aggregate coal demand to the price of alternative energy types is indicated in Table 137. The impact of a plus or minus $5.00 per barrel shift in crude oil price is a $0.71 per MM Btu's shift in satisfactory net-back levels.* Basic information for undertaking the sensitivity analysis is contained in the net-back tables (Tables 125-134). For example the lower oil price effectively means a net-back of 1.62/ton ($0.91 + $0.71) would be necessary at Coalspur if a market was to be penetrated, rather than the $0.91/ton net-back figure under the base case price assumptions. Similarly if the oil price is assumed $5.00/bbl. higher any net-backs for Coalspur above $0.19/ton as shown in the tables would be identified as potential coal markets. Thus the compilation of aggregate demand may be undertaken on the following basis:

Crude oil price ($/Bbl)	15.00	20.00	25.00
	satisfactory net-back ($/MM Btu's)		
Cape Breton	2.11	1.40	0.69
Coalspur	1.62	0.91	0.19
Drumheller	1.21	0.50	-0.21
Bienfait	1.13	0.42	-0.30

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* *$5.00/barrel ÷ 6.3 MMBtu's/barrel x 90% (relationship of HFO price to crude oil on a volumetric basis). All other energy prices are assumed to bear a constant relationship to the crude oil based HFO price.*

TABLE 137: AGGREGATE COAL DEMAND SENSITIVITY TO PRICE OF ALTERNATIVE ENERGY TYPES

	Crude oil price/Bbl.					
	$15.00		$20.00		$25.00	
	$(10^{12}$Btu's)					
			1990			
British Columbia	6.1		19.3		30.4	
Alberta	11.1		158.7		178.9	
Saskatchewan	10.2		24.3		37.9	
Manitoba	12.6		15.8		23.3	
Ontario	18.0		76.8		246.5	
Quebec	32.7		74.9		166.5	
Atlantic	7.6		8.7		49.9	
CANADA	98.3	(4.92)*	378.5	(18.93)*	733.4	(36.67)*
			2000			
British Columbia	6.0		24.2		37.6	
Alberta	12.7		218.9		239.2	
Saskatchewan	14.5		32.8		47.8	
Manitoba	13.7		19.8		27.3	
Ontario	18.4		86.3		293.4	
Quebec	32.8		84.5		190.1	
Atlantic	7.9		11.4		49.7	
CANADA	106.0	(5.30)*	477.9	(23.90)*	885.1	(44.26)*

* *Short tons using an average coal calorific conversion value of 20 x* 10^6 *Btu/ton.*

APPENDIX A

ORGANIZATIONS CONSULTED DURING THE COURSE OF THIS STUDY

Private Sector

Alsands Mining Development
Manalta Coal Ltd.
Potash Company of America
Interprovincial Steel and Pipe Corp. Ltd.
Francana Minerals Ltd.
Babcock and Wilcox Canada Ltd.
The Steel Company of Canada Ltd.
Hudson Bay Mining and Smelting Ltd.
Inco Ltd.
Combustion Engineering Canada Ltd.
Consolidated-Bathurst Ltd.
Domtar Chemicals Ltd.
Canada Cement LaFarge Ltd.
Iron Ore Company of Canada Ltd.
Sydney Steel Corporation
Kaiser Resources Ltd.
Western Co-Operative Fertilizers Ltd.
Polysar Limited
Dow Chemical of Canada Ltd.
HudBay Coal Ltd.
Luscar Limited
Canada Steamship Lines Ltd.
Valley Camp Limited
Thunder Bay Terminals Ltd.
CN Rail
CP Rail
Arrow Transportation Systems Incorporated
Upper Lakes Shipping Limited
Quebec and Ontario Transportation Co. Ltd.
Canadian Pulp and Paper Association

Public Utilities and Crown Corporations

Saskatchewan Power Corporation
Potash Corporation of Saskatchewan
New Brunswick Electric Power Commission
Cape Breton Development Corporation
Nova Scotia Power Corporation
B. C. Hydro and Power Authority
Manitoba Hydro
Ontario Hydro
Hydro Quebec
The Consumers' Gas Company
Northern and Central Gas Corporation
Newfoundland and Labrador Hydro

Government of Canada

Dept. of Regional Economic Expansion (Saskatoon)
Dept. of Energy, Mines and Resources

Provincial Governments

Saskatchewan Dept. of Mineral Resources
Saskatchewan Dept. of Industry & Commerce
Alberta Department of Transportation
Alberta Petroleum Marketing Commission
Ontario Ministry of Energy
Nova Scotia Energy Council
Nova Scotia Dept. of Development
New Brunswick Dept. of Natural Resources
New Brunswick Dept. of Commerce and Development

CANADIAN ENERGY RESEARCH INSTITUTE

PUBLICATIONS

Studies

No. 1 The Availability of Capital to Fund the Development of Canadian Energy Supplies. J.R. Downs. November, 1977 (Price $3.00, 109 pages).

No. 2 The Industrial Demand for Oil and Gas in Ontario. DataMetrics Limited. March, 1978 (Price $3.00, 119 pages).

No. 3 The Effects of Rising Energy Costs on Canadian Industry. Anthony P. Ellison. April, 1979 (Price $3.00, 62 pages).

No. 4 Potential Markets for Thermal Coal in Canada, 1978-2000: Summary and Conclusions. Canadian Resourcecon Limited. June, 1979 (Price $3.00).

Working Papers

78-1 Drilling and Field Construction Costs in the Canadian Petroleum Industry. Gordon M. Engbloom, Confer Consulting Limited. January, 1978 (83 pages).

78-2 Some Supply Price Estimates for Synthetic Crude Oil in Canada. Z. Charles Slagorsky. April, 1978 (42 pages).

78-3 Past and Future Energy Costs in the Canadian Economy. Anthony P. Ellison. April, 1978 (136 pages).

78-4 Canadian Electric Utility Industry Costs, 1960-1990. Gerard J. Protti. May, 1978 (218 pages).

78-5 Enhanced Oil Recovery Potential in Canada - A Methodological Preview. J. Philip Prince. June, 1978 (184 pages).

78-6 Regional Energy and Production Data for Canadian Manufacturing Industries: 1962-74. Robert N. McRae and Alan R. Webster. July, 1978 (106 pages). OUT OF PRINT.

78-7 Regional Demand for Energy by Canadian Manufacturing Industries. Robert N. McRae. October, 1978 (132 pages).

79-1 An Input-Output Analysis of the Effects of Rising Energy Costs on Canadian Industries. Anthony P. Ellison. April, 1979 (246 pages).

79-2 Potential Markets for Thermal Coal in Canada, 1978-2000. Canadian Resourcecon Limited. June, 1979 (321 pages).